Review of the regulatory framework for the electricity sector in the Turks and Caicos Islands

Prepared for the Turks and Caicos Islands Government

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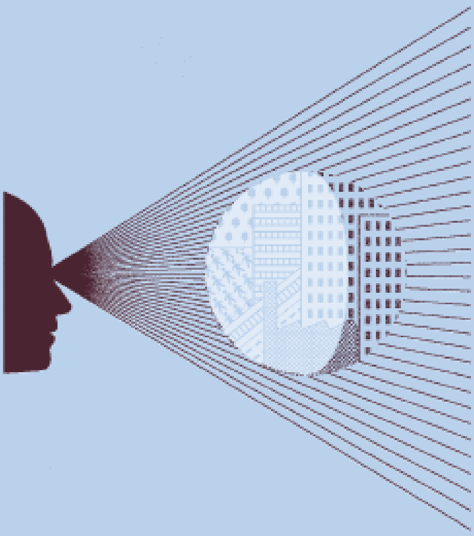

Executive summary

The Turks and Caicos Islands Government (the TCI Government) commissioned Oxera to undertake an independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands (TCI).

As set out in the terms of reference,[1] the primary aims of Oxera's review were to:

– assess the costs and tariffs of Fortis TCI Ltd and Turks & Caicos Utilities Ltd (TCU) in relation to appropriate regional and international comparators;

– assess the effectiveness of the current regulatory framework in terms of its administrative and economic efficiency;

– make recommendations for a revised regulatory framework and Electricity Ordinance; and

– make recommendations for the implementation and operation of a revised regulatory framework, having regard to the scale and capacity of the TCI Government.

Oxera's regulatory review has been undertaken against a background of widespread concern about the level and volatility of electricity prices in TCI and the lack of development of alternative energy sources such as renewable generation. Moreover, as became clear in the early stages of the review, both the TCI Government and the electricity companies expressed concerns about the effectiveness and efficiency of the existing regulatory framework and how this is implemented.

While the need for change may be apparent to the majority of stakeholders, the direction that this change should take is less clear.

The review first focused on understanding the features of the TCI electricity sector and the current regulatory regime. This has included gaining an understanding of a wide range of stakeholders' views on the issues facing the sector. It has also included an examination of the electricity tariffs charged to consumers on TCI and the cost drivers faced by the electricity companies on TCI (in particular, in comparison to electricity providers in other Caribbean jurisdictions). The financial performance (profitability) of the electricity companies on TCI has also been examined.

This has then been followed by an assessment of the suitability of the existing regulatory system to deliver against some important principles that regulation should seek to deliver. Bearing in mind the operating circumstances of TCI—in particular, its small size and remoteness—options for reform have then been developed that might better meet these principles. Some initiatives would require incremental changes to the existing system, whereas others would require more fundamental reform. Finally, recommendations are provided for a future model of electricity regulation on TCI.

[1] Turks and Caicos Islands Government (2011), 'Review of the regulatory framework for the electricity sector in the Turks and Caicos Islands: Terms of reference', June 30th.

The current system

Electricity services on TCI are provided by two vertically integrated companies: Fortis TCI and TCU, each of which has an exclusive territory within which to generate, transmit/distribute, and sell electricity on the islands. The companies rely entirely on diesel generating units of various types to generate electricity. Fortis TCI is the larger of the two companies, serving around 85% of all customers on TCI.[2]

The current system of regulation on TCI centres on the process for rate-setting, as laid down in the relevant Ordinance[3]. While there are provisions for a rate review, these have been somewhat infrequent. Indeed, TCU's base-rate tariffs have remained unchanged in nominal terms since takeover in 1986. The companies are, however, protected from fuel price increases through the fuel cost adjustment, which has become a growing element of end users' bills. Historically, this adjustment, plus the historical demand growth in TCI, made the fact that base rates had remained largely unchanged somewhat less problematic. More recently, this has become more of a concern for the utilities, given past investment in generating capacity, the impact on demand of the global economic slowdown, and the investments necessary to restore services following Hurricane Ike in 2008.

Any regulatory regime should have as its principal concern the welfare of consumers, although it is not clear that maintaining the current regime is in their best interest. For example, many consumers claim not to understand their bills (especially the fuel cost adjustment component), or what the current system of regulation allows for. Moreover, there is widespread concern that rising electricity bills are becoming unaffordable and a lack of understanding of why renewable energy sources remain underdeveloped. That said, many stakeholders have praised the companies for their reliability and prompt response in times of emergency, especially following Hurricane Ike.

Oxera understands that the companies are prepared to embrace changes to the current regime, so long as this makes it more transparent, independent and predictable. This includes changes to incentives to increase efficiency, and a regulatory regime that incentivises renewable energy. At the same time, the companies consider that the terms of their licences need to continue to be respected, and that fuel costs should continue to be passed through to customers as such costs are largely beyond the control of the companies.

Tariffs and costs

The residential tariffs charged by TCU and Fortis TCI are among the highest in the Caribbean. However, in general, larger jurisdictions in the Caribbean appear to have lower tariffs than smaller jurisdictions, indicating that there are economies of scale in electricity provision.

While many Caribbean jurisdictions suffer from lack of scale when compared to electricity systems in the United States or Europe, TCI is among the smallest—and more remote—jurisdictions in the Caribbean. These factors limit the potential for a more diverse mix of fossil fuels to be used on the islands (fuel is imported in relatively small quantities via the Bahamas and there is a lack of deep water ports). Owing to its remoteness, electrical interconnection possibilities between TCI and other jurisdictions are severely limited. Taken together, the costs (and tariffs) of electricity are high due to the circumstances present on TCI. These give rise to a high dependence on diesel, high fuel purchasing costs, and high capacity reserve margins. Having said this, the generating capacity margins of both TCU and Fortis TCI are high by the standards of Caribbean utilities (although TCU has a particularly small operating area), and it is unclear whether these capacity margins are efficient.

[2] See CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

[3] Electricity Ordinance, May 15th 1998.

Both companies have invested significantly in their assets over recent years. Much of the capital investment undertaken was a legacy of growth in peak demand before 2008, which has since abated. Since then, TCU has switched priorities to investing heavily in network restoration, following the impact of Hurricane Ike, which might be regarded as investment that it had little choice but to undertake. Fortis TCI has continued to invest in new generation capacity and a new headquarters since 2008, which has improved the condition of its assets and safety performance. While the investments made by both companies have led to highly reliable systems, significant investment has been undertaken, and the extent to which this has necessarily been efficient is not clear.

In addition, an indicative analysis of labour productivity presents mixed evidence on the operating efficiency of the companies. Taking account of their size (and employing significant adjustments to the employee figures submitted by Fortis TCI to CARILEC), the companies appear to be ‘about average’ for the Caribbean on labour productivity. This indicates that they both are likely to have scope to improve, however.

An analysis of the companies’ operating costs shows that generation costs (including fuel costs) are very significant elements of total costs. Fuel costs are also largely beyond the utilities’ control. The level of risk implied by this cost driver would support the retention of a mechanism (such as the fuel cost adjustment) to enable it to be passed through to customers. Other areas of cost are either partly controllable, or much less significant than fuel costs in terms of cost risk. This implies that while some categories of non-fuel costs may increase, these increases may be largely or entirely offset by reductions elsewhere. In turn, this implies that regulatory incentives could usefully be applied to encourage greater operating efficiencies.

Financial performance

This report has undertaken an analysis of the profitability of the TCI electricity companies, to explore whether their profitability levels are ‘reasonable’.

The returns to Fortis TCI and TCU since 2008, of around 7.5–9%, appear to be broadly consistent with benchmark returns that investors would have been likely to expect from investing in TCI companies as measured by the ‘weighted average cost of capital’ (WACC). Historic returns prior to 2008 appear to have been significantly higher than this. Owing to the high level of capital investment incurred to replace assets following Hurricane Ike, it could be argued that the book value of assets is a closer approximation of replacement costs in recent years; hence, it would follow that the return on capital employed (ROCE) estimates since 2008 provide a more accurate reflection of the economic profitability of the TCI electricity companies compared with earlier years. Similarly, the return estimates in earlier years may have been biased upwards due to the lack of accurate information on replacement cost for those years.

However, the key driver in the lowering of the level of returns since 2008 appears to be the investment in fixed assets, and not the decrease in operating profit. ROCE is a measure sensitive to changes in the asset base, and some variability in the results is therefore not surprising.

It is also important to note that, to the extent that a utility undertakes excessive investments in capacity leading to idle plant or underutilised assets, it is possible that measured profitability may be at a ‘reasonable’ level at the same time as customers are charged excessively high tariffs. Therefore, going forward, it is important that the regulatory framework put in place allows for some justification of the need for investments, as well as a forward-looking assessment of the cost of capital that companies should be allowed to earn, to be provided by the companies.

Existing regulatory framework and principles of economic regulation

An assessment of the existing system is set out in the table below, introducing and describing the principles of economic regulation, and comparing the existing regime in relation to each principle.

The principles of economic regulation and the existing regime

Principle	Principle description	Assessment of the existing regime
Government policy objectives		
Tariff structures and renewable energy policy	Government policy objectives need to be clarified and taken into account by the regulatory framework	Currently, there is no clear policy to promote energy from renewable sources Government policy on fair treatment of different customer types in charging is unclear. The electricity companies are also not constrained by non-discrimination clauses when deciding on tariffs applied to different customer classes
Promoting the interest of consumers		
Limiting 'excess' monopoly profits	Tariffs should be aligned with costs—ie, such that companies can cover their costs, including a return on investments equal to the cost of capital	The tariff structure (base rate and fuel cost changes) is unlikely to reflect costs, unless by coincidence
Incentives to improve efficiency and quality of service	Utilities should also have incentives to improve their operating and capital expenditure (OPEX and CAPEX) efficiency	The current regulatory framework does not require companies to seek or impose OPEX efficiency targets In addition, the lack of regulatory scrutiny and need for justification of investments, coupled with the companies' expectation that they will earn a return of 15/17.5% on the assets, are likely to be drivers for overinvestment
	Utilities should also have incentives to improve their quality of service	TCI electricity companies provide a service that is perceived as highly reliable. However, customer care is perceived as poor
Financing of functions	The regulatory system should allow companies to be able to finance their functions	There is currently a lack of clarity over the methodology to establish the level of return that investors can expect to earn from investing in TCI electricity companies. The companies' expectation is that they are entitled to a 15/17.5% return
Promoting competition and/or third-party participation	Promote competition and/or third-party involvement when appropriate (ie, where this is both feasible and desirable)	Given the size of the islands, vertical separation of the TCI electricity companies would entail costs higher than the benefits, as would full market liberalisation However, the legislation seems to prevent entry by other public suppliers in developing renewable energy sources. Forms of competition and/or third-party involvement in constructing new assets could be encouraged in this area, depending on government policy towards renewables (see above)
Appropriate regulation for the setting	In a small-island context, the regulatory system should deliver benefits, while being both proportionate to the setting and practical to implement	There are some benefits to the existing regime. However, it appears to be poorly designed, is too prescriptive and process-orientated, and encourages debate around legal interpretation rather than on economic merit
Institutional set up	The adequacy of the institutional set-up is central to make the regulatory process work and assure the buy-in and trust of all relevant stakeholders, including the regulated companies.	Currently, regulatory decisions are ultimately taken by Governor. Stakeholders, in particular companies, perceive that this exposes the regulatory process to political influence.

Principle	Principle description	Assessment of the existing regime
Transparent regulation	The transparency of the regulatory process is key to reducing risks that arise from the process itself, to allow stakeholders to position themselves appropriately within that process, and to understand the process outcomes	Currently, none of the key stakeholders perceives the regulatory framework to be transparent (ie, customers, the government and the electricity companies)

Source: Oxera.

Some of the principles described are complementary, whereas others may conflict to some extent. Therefore, there is no perfect system, and in practice any regulatory system must make trade-offs and be sensitive to the local conditions. However, what is clear is that the existing regulatory regime 'falls short' on the above principles in a number of respects. As such, options for regulatory reform of the TCI electricity sector that appear more consistent with the principles have been explored.

Options for a new regulatory framework?

There are a number of measures that could be adopted to improve regulation of the electricity sector in TCI, in order to better address the principles described above. The types of reform explored by Oxera can be grouped under the three headings below. Oxera has explored options that might be introduced under the existing legislation, and more fundamental reforms that would require new legislation.

Policy context + Core regulatory model + Institutional set-up and transparency of regulation

What options exist for better addressing the key regulatory principles?

– **The policy context**—this includes options to facilitate energy from renewable sources; and options in relation to achieving cost-reflective and/or 'fair' tariff structures across different customer classes.

– **Core regulation**—this includes options that could be pursued under the existing regime, using voluntary initiatives under the existing legislation, versus more fundamental reforms to the core regulatory model (including a price cap regime, coupled with a building-block approach).

– **The institutional set-up and transparency of the regulatory process**—this includes options regarding the degree of independence of regulation, resourcing issues, and information requirements. Also discussed is the potential for stakeholder engagement in the process, and the possibility of establishing a fund to deal with hurricane events.

Policy context—promoting renewables

It is proposed that the TCI Government clarifies its policy on renewable energy and outlines a plan to implement this policy. The regulatory framework would then be able to take the policy into account.

Oxera has identified shorter- and longer-term measures that the TCI Government could undertake to promote energy from renewable sources using a two-stage strategy:

– **shorter-term measures** that are implementable without major changes to the industry set-up (eg, changes to the tariff structure to incentivise energy efficiency by customers);
– **longer-term measures** that comprise a menu of options that need to be explored and their feasibility assessed before implementation is pursued (eg, the introduction of a grid code and feed-in-tariffs for new suppliers and self-generators).

Nevertheless, what needs to be recognised is that, for the foreseeable future, diesel will play a large part in the energy mix on TCI, and, moreover, that escaping this legacy is more about diversity in generation than about carbon emissions.

In addition, given an announcement by the TCI Government in 20011 to potentially introduce a carbon tax, it needs to be recognised that, if a building-block approach to regulation were introduced in future (as part of a price cap approach—see below), any carbon tax would be likely to be passed on to consumers in prices. If introduced, the carbon tax element should be identified clearly on consumer bills in the interest of transparency.

Policy context—tariff differentials between customer classes

The TCI Government should also clarify its policy on social and rebalancing issues in tariff-setting. This is relevant in the case of both incremental changes to the existing rate base approach and more fundamental reforms (see below).

In general, for tariff differentials to be scrutinised effectively by the regulator, a clear articulation of the cost differentials (if any) that are relevant and which justify the tariff differentials is needed from the companies, and the same is needed for any government policy (eg, the promotion of tourism, social issues) that is being pursued through tariff differentials. Only if the rationale for the differentials is set out can the regulator evaluate their fairness or efficiency.

Core regulation—incremental versus fundamental reform

The existing regime has some benefits in terms of TCI securing high reliability. Information is provided on an annual basis on key financial and operational issues for monitoring purposes. Radical change would also bring about costs, in terms of revisions to the Ordinance, and regulatory restructuring, hiring and training. The companies themselves would also need to adapt to any new regime.

For these reasons, some measures that could be undertaken under the *current* system of regulation, and under existing legislation, have been considered. Discussions with stakeholders revealed that consumers do not understand the fuel cost adjustment, and that the regime is too prescriptive and process-orientated. Changes that could be introduced are as follows.

– **Base rates and fuel costs**—these could be updated to include a best estimate of fuel costs at the start of each financial year.
– **Fuel cost adjustment and efficiency**—the fuel cost adjustment could factor in a more realistic and up-to-date assumption on fuel-burn efficiency, and could be communicated more effectively to customers. The companies could also publish, in advance, what bills are likely to be in the coming months, to help consumers budget better.
– **Investment assessment**—a voluntary arrangement could be introduced whereby the Electricity Commissioner can review (and advise on the prudence of) the investment plans of an electricity company before large investment is committed.
– **Operating and performance efficiency**—the companies could volunteer to share with the Commissioner evidence of their initiatives to improve efficiency.
– **Customer engagement**—the companies could sign up to a voluntary arrangement to undertake engagement with their customers on investment plans before pursuing these.

– **Service performance**—the companies could also sign up to developing customer-facing service measures, and to publish their performance on these on a regular basis.

However, these potential changes may not radically alter the incentives present under the existing regime, for example with respect to efficient levels of investment or OPEX. Many of these changes would rely on voluntary initiatives, which the companies may or may not sign up to.

A potential alternative is that, accompanied by legislative changes to support it, price cap (or 'RPI – X') regulation could be introduced. This has fundamentally different incentive properties to the rate-base approach. Typically forward-looking, price cap regulation could incentivise the companies to become more efficient, while revealing information on efficient costs through observed company behaviour over time. It would, however, still need to be accompanied by an adequate pass-through mechanism to deal with variations in fuel costs. Implementing price cap regulation would require changes to the existing legislation. The initial control period over which prices could be fixed could be 3 to 5 years, in order to bed the system down.

If a price cap regime were implemented, an important step would be for the regulator to assess the revenue that a utility should be able to recover through customer bills over the future years over which the cap applies. One way of doing this is to use a 'building-block' approach to determining the revenue allowance. This would include assessing future (efficient) OPEX and CAPEX, the appropriate asset base, and the cost of capital. Price cap regulation does not have to involve a building-block approach, but it does smooth the impact of CAPEX between current and future customers, while providing some certainty to investors that (efficient) future CAPEX will be recovered in prices.

The way in which price cap regulation might realistically be applied in TCI cannot, and should not, mirror the full host of detail and information requirements often observed in larger jurisdictions implementing this regime (such as the UK, and certain US states). Rather, the approach should be proportionate to the situation faced in TCI, in terms of the scope of regulation, the information requirements, and who does what. In practice, this will mean addressing what is typically involved in setting up a price cap regime, but always bearing in mind the TCI-specific context.

Institutions—regulatory style and powers

If price cap regulation were adopted, in the way set out above, this would require changes to the Ordinance, regulations, licences, and final legal clarity on issues in the takeover agreements. It would be important to ensure that the regulator is sufficiently independent from the government, which would also require changes to the Ordinance. However, full independence may be difficult to achieve in a small-island setting.

Were price cap regulation and an independent regulator to be introduced in TCI, the emphasis would need to be on *getting right the aspects that really matter*. Yarrow and Decker (2010) refer to this, in a small-island context, as being about 'doing a limited number of biggish things well', rather than seeking to cover many issues in detail.[4]

The system would need to be transparent and not overly adversarial. The regulator would have a range of duties to take into account in setting charges, and would have powers to demand information from the companies. In undertaking a price review, important issues concern which areas the regulator would mainly work on (eg, the required return), and which

[4] Yarrow, G. and Decker, C. (2010), 'Review of Guernsey's utility regulatory regime', Regulatory Policy Institute, A report for Commerce and Employment.

areas the companies would be expected (and incentivised) to work on (eg, business planning, including the assessment of efficiency and investment).

Institutions—resourcing strategies

As noted, regulation is typically more challenging on small-island economies (due to the fixed costs involved relative to the size of population served, and the potential lack of human resources). In this regard, in setting up an independent regulatory body, various strategies are available, including:

- introducing a stand-alone independent regulator for electricity services;
- introducing a multi-sector regulator across various TCI services;
- engendering closer corporation with other Caribbean jurisdictions;
- accessing available funds from The World Bank and other institutions;
- using external experts for key phases of work (via outsourcing).

Introducing a stand-alone electricity regulator, if this includes a full complement of full-time regulatory resources, may not be viable in TCI. One approach to mitigate this problem could be to adopt a multi-sector regulator. However, because TCI is among the smallest of the Caribbean jurisdictions, it may not have the scope of ongoing activity across sectors and the population or tax base to justify the creation of a multi-utility regulator. While a multi-utility approach might be viable in TCI if in 'skeletal' form, involving extensive use of external consultants as and when required (in order to reduce set-up and fixed administration costs), it is unlikely to be sustainable as a stand-alone entity employing full-time staff in each of the sectors to be covered. Indeed, using external experts for key phases of work, through outsourcing, would seem to be a more viable strategy, under whatever regulatory body is created.

From discussions with stakeholders, it has also emerged that, historically, TCI has not cooperated as much as it might have with other Caribbean jurisdictions. There is merit in considering how sharing of ideas and resources with other Caribbean jurisdictions might benefit TCI going forward. There is also merit in considering what funds might be available from external bodies to help set up independent regulation in TCI.

Institutions—including stakeholders in the process

Under either a revised rate-base approach or a system of price cap regulation, the transparency of the regulatory framework could be improved by embedding the stakeholder engagement in the regulatory regime. An example of how this could work under a price cap regime, with new legislation in place, is as follows—the companies:

- would be required to undertake stakeholder engagement in formulating their business plans;
- should speak to and balance the needs of different customer interests (eg, hotels versus residential);
- should take account of government policy (eg, renewables);
- should seek efficient solutions to investment where users can be involved (eg, demand reduction; solar energy);
- should seek efficient solutions to investment where third-party users can be involved (eg, wind energy).

The regulator would then assess whether the company has performed this engagement exercise adequately, and, where this is not the case, require it to engage further. Ultimately, it would be for the regulator to decide whether adequate engagement has taken place, and to balance the needs (in particular) of current versus future customers. However, where customers have clearly signed up to specific investment activities, it would be expected that the initiatives would be allowed for by the regulator in the prices set (subject to other parameters, such as the weighted average cost of capital and efficiency assumptions).

Institutions—strategies for dealing with hurricane events

At present, there is no explicit mechanism in TCI to deal with restoration of the electricity network after a hurricane. If price cap regulation (coupled with a building-block approach) were introduced, based on a forward-looking assessment of likely costs (including efficiencies), a more explicit mechanism than exists at present would most likely be required for dealing with hurricane events. Two alternatives are:

– an explicit contingency within allowed revenues for potential hurricane events (at present, this is implicit);
– the provision to re-open the price review process in the event of a hurricane (if, for example, this were material, *and* would not be financeable if dealt with at the next review).

Both options have their respective advantages and disadvantages. The advantage of the contingency option is that it would smooth the impact of any potential bill increases, but consumers would pay upfront for a contingent event. Effective transparency and governance of any fund would also be critical.

Deciding on the most appropriate model for TCI

While modifications to the existing rate-base regime have been identified that could improve the current situation, it was noted that these might not go far enough to address the identified shortcomings—for example, in relation to incentivising OPEX and CAPEX efficiency.

More independent regulation, coupled with a price cap approach, could instead be introduced (albeit with pass-through for uncontrollable fuel costs). This has more powerful incentives for companies to become efficient, and would reveal information on costs through company behaviour.

Nonetheless, price cap regulation would need to be proportionate to the situation in TCI, in terms of its scope, the information requirements, and who does what. In practice, this would require addressing what is typically involved in setting up a price cap regime but considering the TCI-specific situation. However, it also needs to be recognised that operating effective rate of return regulation using a modified rate-base approach would still require additional regulatory input and analysis.

Following discussions, the TCI Government expressed two main concerns with some of the more fundamental options for reform:

– a ‘multi-sector regulatory agency’ could be too costly to implement in TCI given the size of the jurisdiction;
– a ‘purer’ form of price cap regulation, compared with incremental modifications to the existing approach, would not deliver sufficient benefits in relation to the costs and risks involved because of the additional resources and activities required.

It has therefore asked Oxera to provide a judgement on how the advantages and disadvantages of following a multi-utility/price cap approach (model ‘A’) compare with maintaining the existing rate-base regime with some incremental modifications (model ‘B’). Oxera understands that these are the two main regulatory policy options now being considered by the TCI Government.

At the centre of this debate is whether, compared with model B, the additional benefits (eg, in the form of greater OPEX and CAPEX efficiency) implied by model A would be expected to outweigh the potentially greater, and more uncertain, costs that could be involved.

An important issue that will determine the cost difference between the two is the extent to which model B relies mainly on historical information (to set future prices) that is readily available, as opposed to seeking to predict a number of factors that are then used to set future prices under model A. However, model B may not be purely backward-looking. Under a rate-base approach, if the regulator has the power to review whether CAPEX or OPEX has been undertaken efficiently (or whether it will be efficient in future), an element of future projections is brought back into the regulatory process. In general, only 'pure' rate of return regulation—in which the firm always recovers its expenditure—can be based entirely on historical data.

Model A would otherwise be broadly in line with the more fundamental reform options discussed above: introducing a price cap regime for undertaking rate reviews, coupled with a building-block approach; establishing an independent economic regulator, with a particular regulatory style and powers; and potentially establishing this body as a multi-sector regulator. This model would involve *several* changes to the existing Ordinance and regulations. The multi-sector regulator approach was, however, presented as one among several strategies to manage the costs involved in setting up and administering a different regulatory regime (and was regarded as a strategy that might not be well suited to TCI).

Model B would not (necessarily) involve establishing a multi-sector regulator, but would still involve creating an independent electricity regulator. In turn, this body would rely on external experts by outsourcing certain activities and tasks required at the time of tariff reviews. Under this model, the regulatory regime would also be largely based on the existing rate-base approach, but with the following modifications:

– implementing a rate-base review every three (to five) years;
– adopting a more robust approach to the treatment of fuel costs in the rate base and fuel cost pass-through mechanism;
– determining with more robustness and clarity the appropriate return on capital and asset base;
– undertaking more robust CAPEX assessment;
– facilitating the integration of renewable generation by independent power producers.

Oxera has qualitatively considered the advantages and disadvantages of models A and B. In particular, the implications for resourcing, degree of regulatory discretion required, potential opportunities for efficiency improvements in the TCI electricity sector, and measurement issues in the TCI context have been discussed.

It is perhaps easiest first to consider the benefits that model B could bring, and then whether the additional benefits (eg, in the form of greater OPEX and CAPEX efficiency) implied by model A would be expected to outweigh the potentially greater, and more uncertain, costs that could be involved.

What seems more certain is that a multi-sector regulator would not be the optimal solution. However, there is still a choice between adopting elements of models A and B based on other aspects of these models. In this regard Oxera considers that implementation of model B would be expected to result in a number of regulatory reforms that would have a reasonable probability of addressing the primary concerns associated with the existing regulatory framework—that is, the allowed return determination, CAPEX assessment, transparency, and the perceived (in)appropriateness of the current working of the fuel cost adjustment.

While there could be incremental benefits of the fuller price cap mechanism associated with model A, it is not clear that it would result in future efficiencies over and above those capable of being achieved in model B. Option B may therefore be preferable since the incremental benefits of model A are likely to be low, whereas the costs could be somewhat higher (in terms of time and human resources).

However, as model B attempts to address the issues around efficiency, and starts to look forwards as well as backwards, rather than simply guaranteeing that the electricity companies recover their incurred costs through time, the complexity (and the associated costs) of model B starts to approach that of model A. Furthermore, model B would still be expected to require some changes to the existing Ordinance and regulations to be implemented and greater clarity achieved over the terms of the takeover agreements. In other words, implementing model B is not likely to be an entirely ‘costless’ exercise.

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Note that in this public domain version of the report, in a few instances, where deemed necessary, some numbers have been removed. Such instances are marked clearly with the notation [✂].

1 Introduction

The Turks and Caicos Islands Government (the TCI Government) commissioned Oxera to undertake an independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands (TCI).

As set out in the terms of reference,[5] the primary aims of the review were to:

– assess the costs and tariffs of Fortis TCI Ltd and Turks & Caicos Utilities Ltd (TCU) in relation to appropriate regional and international comparators;
– assess the effectiveness of the current regulatory framework in terms of its administrative and economic efficiency;
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– make recommendations for the implementation and operation of a revised regulatory framework, having regard to the scale and capacity of the TCI Government.

Oxera's regulatory review has been undertaken against a background of widespread concern about the level and volatility of electricity prices in TCI and the lack of development of alternative energy sources such as renewable generation.

Moreover, as became clear during the early stages of the review, both the TCI Government and the electricity companies expressed concerns about the effectiveness and efficiency of the existing regulatory framework and how this is implemented. For example, the existing regulatory framework is in practice implemented through ad hoc requests from the electricity companies for rate variations (typically to increase prices), which then need to be scrutinised and negotiated within constrained timescales. As a result, the TCI Government remains concerned that it is unable to provide sufficient scrutiny of the economic, financial, and technical aspects of these proposals, given the scarcity of suitably qualified and experienced professional resources. In addition, there is the concern that, at present, the Electricity Commissioner has limited powers to demand from the companies the information necessary to facilitate a detailed analysis of their rate variation requests.

In turn, the electricity companies have expressed concerns that the current regulatory framework does not necessarily ensure objectivity and independence from political influence in regulatory decisions, especially in relation to decisions about electricity tariffs. This may increase the perception of regulatory risk.

These concerns over the existing regulatory regime raised by various stakeholders highlight that, as it stands, the regime may not be safeguarding the interests of current and future customers, by failing to:

– ensure that tariffs reflect the costs of the service;
– promote efficient operations on the part of the electricity companies;
– encourage efficient consumption of electricity by TCI consumers;
– incentivise the appropriate level and type of investment over the long term, which would be necessary to facilitate delivery of energy policy objectives, such as the promotion of renewable generation.

Consequently, a comprehensive package of regulatory reform proposals may be necessary that encompass the following broad themes:

[5] Turks and Caicos Islands Government (2011), 'Review of the regulatory framework for the electricity sector in the Turks and Caicos Islands: Terms of reference', June 30th.

– improving the transparency to the regulatory authorities of both prices to consumers and companies' costs;

– strengthening the institutional framework to ensure effective, independent regulation, while recognising the TCI Government resource constraints and the potential impact of the regulatory 'burden' on the electricity companies;

– improving the economic framework governing the conduct of regulation to strengthen incentives for the efficient operation and utilisation of, and investment in, electricity infrastructure;

– embedding stakeholder engagement in the regulatory process, in particular by enabling all representative stakeholders to have their views heard on proposals related to capital investment, given its significance for the prices paid by existing and future consumers;

– facilitating the development of renewable generation;

– formulating strategies for dealing with 'high-impact, low-probability' events, such as hurricanes.

Oxera's approach to this regulatory review was to draw extensively on stakeholder views of the current regulatory regime elicited through numerous face-to-face meetings, correspondence received directly from stakeholders, and detailed information requests issued to the TCI Government and the electricity companies.[6]

An important question for the review was to consider whether any changes to the regulatory regime should be through incremental alterations to the existing 'rate base' system, or through more fundamental reforms, such as moving to 'price cap' regulation.

Based on consideration of stakeholders' views and Oxera's analysis, presented in this report, a package of reform options has been developed, with detail on how they may be implemented in practice. Care has been taken to ensure that the options are targeted and proportionate to the specific circumstances in TCI; namely, its relatively small population and geographical remoteness, which make it important that any new form of regulation does not place an undue 'burden' on consumers, electricity companies, and the TCI Government.

The report is structured as follows:

– section 2 gives an overview of the electricity sector in TCI and describes the existing regulatory regime, including a summary of the governance arrangements in the sector. A comparison is made with the regulatory regimes in other Caribbean jurisdictions, before highlighting the challenges that the TCI electricity sector is facing, as identified by stakeholders;

– section 3 presents evidence on the level of electricity tariffs in TCI compared with other Caribbean jurisdictions, and highlights possible drivers of the regional differences observed in tariffs. This section also compares the TCI electricity companies against other regional comparators along several dimensions relevant to assessing operating efficiency. Lastly, an overview is given of the cost structures of Fortis TCI and TCU;

– section 4 presents evidence on the financial performance of Fortis TCI and TCU by analysing their historical profitability. By comparing the companies' historical returns to

[6] Meetings were held in TCI in August 2011 with representatives from various TCI Government departments, the Consultative Forum and Advisory Council, the electricity companies, Chambers of Commerce in Grand Turk and Providenciales, and trade associations. Stakeholders were also invited to submit written responses directly to Oxera as part of a public consultation. See Turks and Caicos Islands Government (2011), 'Independent Review of the Regulation of the Electricity Service Sector', press release, August 4th.

benchmark returns reflecting their costs of capital, this section provides an indication of whether the companies' profitability is likely to have been reasonable. The profitability of a sample of other Caribbean utilities is also presented;

- section 5 illustrates principles that can be used to design an effective system of electricity regulation. Given that the existing system 'falls short' on these principles in a number of respects, some options for regulatory reform of the TCI electricity sector that appear more consistent with the principles are explored. Some of these options are possible within the existing regime, while others would require more extensive reforms and/or may be longer-term in nature;

- section 6 then gives more detail about how the options described in section 5, if pursued, could be implemented in practice in TCI, and the outstanding issues that would need to be resolved;

- section 7 takes account of feedback from TCI Government on the options explored in sections 5 and 6, and, on this basis, appraises the advantages and disadvantages of two alternative models of regulation that might be taken forward in TCI. The section concludes with recommendations on a preferred model.

Appendix 1 provides further information on the assumptions behind the analysis presented in section 4, focusing on the principles of profitability assessment and the cost of capital calculations. Appendix 2 discusses further the resourcing issues that emerge in Caribbean electricity regulation, following a discussion of these issues in section 6.

2 Electricity services in TCI

This section gives an overview of the electricity sector in TCI and describes the existing regulatory regime, including a summary of the governance arrangements in the sector. A comparison is made with the regulatory regimes in other Caribbean jurisdictions before highlighting the challenges that the TCI electricity sector is facing, as identified by stakeholders.

2.1 Overview of the electricity sector in TCI

Electricity services on TCI are provided by two vertically integrated companies: Fortis TCI and TCU, each of which has an exclusive territory within which to generate, transmit/distribute, and sell electricity on the islands. The companies rely entirely on diesel generating units of various types to produce electricity on TCI.

Fortis TCI is the larger of the two companies, serving around 10,745 customers, or around 85% of all customers on TCI.[7] It operates a fully integrated system, generating and distributing energy on Providenciales and to neighbouring North Caicos and Middle Caicos, under an exclusive 50-year licence that is due to expire in 2037. Fortis TCI was formerly known as Provo Power Company (PPC). PPC was renamed in July 2011 to better align the brand with that of the parent company Fortis Inc, a distribution utility in Canada.[8]

Overall peak demand across the entire Fortis TCI customer base reached approximately 31MW in July 2010.[9] As at December 2010, the company had a total installed generating capacity of 54MW using both medium- and high-speed Caterpillar diesel generating units, 51MW of which is installed on Providenciales, with 3.3MW of standby capacity at North West Point and North Caicos.[10] The commissioning of two additional medium-speed Wartsilla diesel generating units on Providenciales, over 2010 to 2011, increased total installed capacity to 71MW.[11]

Also part of Fortis TCI, Atlantic Equipment and Power (AEP) operates a separate stand-alone generating station and associated distribution infrastructure on South Caicos under an exclusive licence that is due to expire in 2036. It has 2.7MW of capacity, installed on the separate the South Caicos system. Fortis TCI eventually plans to interconnect South Caicos to the main system on Providenciales.[12]

TCU provides electricity to around 1,930 customers (around 15% of customers) on TCI. Operating under a 50-year licence issued in 1986,[13] it generates and distributes electricity on Grand Turk and on Salt Cay. These systems are not currently interconnected, although they have been in the past. The business has a total installed generating capacity of 11MW across the two systems.[14] TCU is owned by WRB Enterprises Inc, a US company.

[7] See CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

[8] Fortis TCI (2011), 'PPC Ltd is now FortisTCI Limited', press release, July 15th.

[9] Fortis TCI (2011), presentation to the TCI Government, February 7th.

[10] Ibid.

[11] Castalia (2011), 'Development of an Energy Conservation Policy and Implementation Strategy for the Turks and Caicos Islands', final report prepared for the Government of the Turks and Caicos Islands, March 31st, p. 13. Fortis TCI (2011), 'Fortis TCI's Second Wartsilla Engine Ready for Operation', press release, August 8th. Fortis TCI (2010), 'PPC Ltd. Announces Arrival of Diesel-Generating Engine to Boost Operations', press release, May 5th.

[12] Fortis TCI (2011), presentation to the TCI Government, February 7th.

[13] See Castalia (2011), op. cit., p. 22; and TCU Takeover Agreement, April 1986, p. 4.

[14] See TCU's System Development Plan, 2011–15.

2.2 Overview of the regulatory regime

2.2.1 Institutions

The governance of the TCI electricity sector is outlined below. The institutional framework, the institutions, and their roles are set out in the Electricity Ordinance, although they have been adapted over time.

– **The Governor** is in charge of granting and revoking licences, and is responsible for setting out ‘regulations’ on the level and structure of tariffs that the companies can charge, and the charges that can be set for different customer groups. As part of the rate review process, the Governor has the power to approve changes to these regulations, and, hence, changes in tariffs. As discussed further below, a rate review may be brought about at the request of either the companies or the Governor, although the Governor is the ultimate authority on regulated electricity tariffs in TCI.

– Reporting to the Governor**,** the **Ministry of Works, Housing and Utilities** receives standardised regulatory filings (Schedules 1 to 9) from the companies at the end of each year. These filings outline the companies’ expenditure and financial situation, including whether the companies, in their view, are making an adequate return on capital.[15] The companies must also submit audited financial accounts annually.

– The **Electricity Commissioner** (the ‘Commissioner’), situated in the Ministry of Works, reviews the above annual information from the companies, and is in charge of overseeing the monthly fuel cost adjustment mechanism. This involves receiving data from the companies and checking the calculation of this mechanism. In addition, the Commissioner is responsible for the inspection and testing of the companies’ electrical plant, to ensure quality of service. Finally, the Commissioner oversees the electricity inspectorate, which examines electrical installations in premises, and regulates electricity in the construction sector.

– The **Department of Environmental and Coastal Resources** (DECR) is responsible for the promotion of sustainable management and natural resources on TCI, and hence, arguably, de facto leads efforts in TCI to develop a policy for energy conservation and renewable generation in the electricity sector.

2.2.2 The Electricity Ordinance and rules for setting tariffs

The Electricity Ordinance 1985 (updated 1998) sets out the approach to electricity tariff-setting on TCI. While it is prescriptive on some issues (eg, the process for rate reviews), it provides room for interpretation on others (eg, the allowed returns to suppliers).

Part V Section 32 of the original Ordinance (1985) and revised Ordinance (1998) requires the Governor to set out, under ‘regulations’, the appropriate tariffs to be charged by PPC and TCU:

> charges made by a public supplier for electricity…shall be in accordance with such tariff of rates as the Governor shall prescribe by regulations.

In setting out tariffs as part of these regulations, the Governor is required under Part V Section 32(3) of the Ordinance to enable electricity suppliers to recover sufficient income that enables them to:

– cover operating expenses (including any taxes) and make provision for maintenance, depreciation and interest payments;
– meet repayments on indebtedness to the extent that these exceed the provision for depreciation; and

[15] Schedule 8 of the annual regulatory filings. This is discussed in more depth below.

– obtain a reasonable margin on profit.

In addition, the Ordinance permitted the Governor to introduce a monthly fuel cost adjustment mechanism within the charging regulations, to reflect changes in fuel costs from month to month.[16]

In the case of TCU, the first tariff regulations were issued in December 1986, setting out base rates for residential, non-residential, and official premises, and for street lighting, together with the workings of the fuel cost adjustment mechanism.[17] Regulations containing the tariffs to be charged by PPC on Providenciales were set out in February 1987. Again, the base rates to be charged to different premises were provided, together with the workings of the fuel cost adjustment mechanism.[18]

Changes to tariffs under the rate review process

If either the Governor or an electricity company wishes to alter the tariffs set out in the prevailing regulations, they can request a rate review under Section 33 or 34, respectively.[19] In practice, a rate review can examine whether to increase or decrease the base-rate tariffs, change the tariff structure (eg, with tariffs applied to different categories of end-user), or modify the fuel cost adjustment mechanism.

The Governor must have regard to the above three core Section 32(3) objectives when deciding whether to change the prevailing tariffs. In practice, this means that any person appointed to hold an inquiry, as part of a rate review, must also have regard to these objectives. If, following a rate review, the Governor concludes that tariffs should be changed, the tariff regulations are amended to incorporate the revised rates. Ultimately, the Governor has the final decision on whether to change the prevailing tariffs and, hence, the regulations.

The rules that apply to a company requesting a rate review are slightly different to those that apply when the Governor requests a review, depending on which party is requesting the review, as set out in the Ordinance. This includes the provision for an inquiry if a company is not satisfied with the Governor's initial decision. Additional stipulations are that the Governor has six weeks to review the request; can request accounts and other information from the company concerned to assist in reviewing the request at an early stage; and, if the company fails to provide this information, can refuse to hold an inquiry.

While there is provision in the Ordinance for a rate review, as noted, the Governor has the final decision on whether any changes to the prevailing tariffs are required. The Governor does not, for example, need to accept the findings of any inquiry report.

In practice, very few rate review requests initiated by the electricity companies have been successful. Oxera is not aware of any such requests initiated by TCU that have resulted in an increase in its allowed base rates. Indeed, it is understood that TCU's base-rate tariffs in 2011 were equivalent in nominal terms to those established in 1986. However, Oxera understands that the base rates for Fortis differ from those established in 1987 (see section 3).

Changes to tariffs under the fuel cost adjustment

As noted, through the development of new regulations, the Electricity Ordinance permitted the introduction of a fuel cost adjustment mechanism.[20] This allows monthly adjustments to tariffs where, due to movements in wholesale oil prices, the unit fuel cost ($/gallon) rises

[16] Electricity Ordinance, May 15th 1998, Sections 32(1) and 32(5), and the charges regulations.

[17] Electricity rates and charges regulations (Grand Turk, Salt Cay and South Caicos), Section 32, Legal notice 52 of 1986. It is of interest that these particular regulations also applied to South Caicos, which is served by PPC.

[18] Electricity rates and charges regulations (Providenciales), Section 32, Legal notice 5 of 1987.

[19] Electricity Ordinance, May 15th 1998, Section 34.

[20] Electricity Ordinance, May 15th 1998, p. 70.

above or falls below the cost assumed in the base-rate tariffs (for more detail, see section 3.1).

Information requirements on the electricity companies

Under the Ordinance, the electricity companies are also required to.[21]

– prepare annual accounts, audited by auditors approved by the Governor;
– provide separate information for generation and distribution and other activities under the public supplier's licence;
– provide the Governor with an annual return, within three months of the end of the financial year, covering property and other activities carried out under the company's licence, containing such information as the Governor may direct.

In practice, this information is supplied annually to the Ministry of Works, Housing and Utilities, and hence to the Electricity Commissioner. As noted, the two companies now also provide information to the Commissioner on their fuel costs and the fuel cost adjustment factor.

2.2.3 The takeover agreements, licences and annual submissions

Key documents also relevant to the regulation of the electricity sector on TCI include the takeover agreements; the licence;[22] and the Section 34 Schedules, through which the companies report performance annually to the Government (including on their rate of return.)[23]

Takeover agreements were signed between the electricity companies and the government when the utilities were privatised (in April 1986 for TCU and January 1987 for PPC). In its takeover agreement, TCU committed to the following operational terms:

– to maintain the distribution network in sufficient working order, but if this could not be maintained as such, to replace the equipment at its own cost.[24]
– to generate all its electricity from its South Base Grand Turk power station and cease operations from the Colonel Murray's Foot Hill Grand Turk power station. TCU was required to expand generation capacity if demand increased.[25]

In its takeover agreement, PPC committed to the following operational terms:

– to maintain its assets in good working order, and replace them at its own cost if they could not be maintained as such;[26]
– to extend its distribution network to regions not currently connected if justified by demand.[27]

In terms of allowed returns, PPC and the (then) government agreed upon takeover that the tariffs for the first year (1987) should enable the company to earn an allowed return of 17.5%. Oxera understands that the companies argue that, on this basis, they continue to be entitled to a return of 17.5% in the case of Fortis TCI and 15% in the case of TCU, plus any cumulative shortfall in the past against this target return.

[21] Ibid, Section VI.

[22] The licence was included as an annex to the Takeover Agreement in the case of both TCU and PPC.

[23] This was included as an annex to the Takeover Agreement in the case of PPC, in response to a request from the (then) Electricity Commissioner. In the case of TCU, these schedules were requested by the Commissioner some months after takeover, given that they were being used in the case of PPC.

[24] TCU Takeover Agreement and Licence 1986, Annex 1, para 8.

[25] Ibid, paras 16 and 17.

[26] PPC Takeover Agreement January 1987, para 8.

[27] Ibid, para 9.

Regardless of the route followed by a company to request an increase in tariffs, the Ordinance states that the Governor should assess what is a 'reasonable' return, before approving any rate changes.

2.3 Challenges to the existing regulatory regime, as identified by stakeholders

The views obtained from stakeholders during Oxera's visit to TCI in August 2011 are considered in this section, together with subsequent discussions with, and submissions from, Fortis TCI[28] and TCU, and submissions to the public consultation.[29]

The issues that the electricity sector on TCI faces are grouped into four key themes:

– electricity prices and quality of service;
– institutional framework and system of regulation;
– energy policy and promotion of alternative energy sources; and
– companies' perceptions of the risks and opportunities of regulatory reform.

Overall, from Oxera's engagement process with stakeholders, it appears that the current regulatory framework is not able to address these issues. The following discusses what the stakeholders reported. In a number of cases, Oxera's initial assessment of the issues raised is also presented.

2.3.1 Electricity prices and quality of service

There is a wide range of views about the factors that drive electricity tariffs in TCI. In general, the tariffs are perceived as being unduly high:

– residential users regard their electricity bills as 'very high', particularly when compared with disposable incomes;

– several stakeholders highlighted how they are already rationing electricity and that there are barriers to the widespread adoption of alternatives (eg, safety concerns associated with the use of liquefied petroleum gas (LPG) for cooking, the upfront costs of energy efficiency measures, or the problems faced in adopting renewable generation technologies); and

– large users are believed to enjoy substantial discounts compared with domestic users, although the basis for these tariff differentials is either unclear or not well understood by customers.

Importantly, in relation to the achievability of lower electricity tariffs, and what policies could deliver better outcomes for consumers in the long term, there is a disconnect between the electricity companies and their customers (as represented by domestic customers, small, medium-sized and large users, and their representatives, such the Consultative Forum, the Advisory Council, the Chambers of Commerce and other trade associations). However, there is also a relatively limited understanding of exactly what prices companies actually charge, and the level and structure of the costs that the companies face. For example, representatives of certain customer groups consistently held the position that the electricity companies are 'monopolists' charging tariffs that are 'excessive'; the implication being that changing the structure of the sector—by enabling direct competition within existing licence areas, allowing self-generation, and forcing the companies to accommodate independent power plants (whether conventional thermal or renewable generation)—would increase competition and lead to lower prices.

[28] For example, Fortis TCI put forward its views on current and future regulation in a document sent to Oxera Fortis TCI (2011), 'General Regulatory Principles', August.
[29] In addition to the visit to TCI in August 2011, Oxera received a number of public responses via a dedicated email address.

In contrast, the electricity companies highlight that their costs are largely driven by factors beyond their control (eg, fuel purchasing costs), and that the regulatory regime in practice provides inadequate investment incentives, while also raising perceptions of regulatory risk. The companies consistently highlighted that TCI electricity tariffs are higher than in other parts of the Caribbean due to the costs of supplying fuel to TCI as a result of its relatively remote location (ie, its lack of proximity to large trading hubs and/or trade routes, and limited fuel importation infrastructure).

A consistent concern among customers and their representatives was that there is a lack of transparency of how tariffs are set. There is also a widely held concern that the existing regulatory regime does not safeguard consumers' interests—for example, consumers:

– are often not able to understand elements of their bills, notably in relation to the power cost adjustment;
– believe that the companies could make more effort to explain the components of the electricity bill and how charges may change over time, not least so that consumers could plan their household budgets and expenditure better;
– believe that the companies could make more effort to explain the rationale for their investment decisions, since it was not clear that this was always efficient, especially if capital expenditure (CAPEX) placed significant upward pressure on tariffs; and
– believe—as the companies have publicised this—that Fortis TCI and TCU are entitled under the existing legislation and rules to earn profits of 17.5% and 15% respectively, but that such returns would be excessive.

Some consumers also believe that, at present, the companies are actually earning returns of 17.5% and 15%—although the companies themselves note that this is currently not the case.

There were also mixed views on the levels of service provided by the companies:

– several stakeholders praised the preparedness of both Fortis TCI and TCU in relation to hurricanes (in particular in 2008), and their responses to storms;
– the operational reliability of the companies (eg, lack of interruptions, etc) was also considered to be high.

Nevertheless:

– concerns were raised regarding a 'lack of empathy' towards customers, and the lack of explicit service-level requirements and incentives in relation to customer inquiries and complaints.

2.3.2 Institutional framework and system of regulation

The current system of regulation is also somewhat hindered by mistrust and frequent disagreement among the main parties. The TCI Government and the electricity companies themselves recognise that their relationship has been, and continues to be, somewhat adversarial, as evidenced by disagreements over past billing arrears. A key concern expressed by Fortis TCI (PPC) and TCU is that the current regulatory system does not necessarily ensure objectivity and independence from political influence, something that increases the perception of 'regulatory risk'. In particular, they noted that the Governor has the ultimate decision on base-rate cases. The justification for past decisions has not, in the companies' view, been sufficiently transparent. This might be regarded as leading to a perpetual price cap (but without the incentives of a price cap).

Furthermore, there is a perception that the Electricity Commissioner's role is limited by the existing legal framework, which is preventing a greater degree of regulatory independence from the government.

It also became fairly clear from discussions that there is an imbalance between the TCI Government/Electricity Commissioner and the companies as regards the available information and resources to perform their respective roles. Although the companies are better resourced than the TCI Government (in particular, through their parent companies, and through participation elsewhere in the Caribbean), they do question whether the information they are required to submit annually to the TCI Government and/or the Commissioner is actually used. The companies also collect a range of asset management and operational data to inform their commercial decisions, but this is not necessarily shared with (or requested by) the Commissioner.

The current framework appears to be overly ‘administrative’ and poorly designed. The Electricity Commissioner has limited powers to demand information or set prices, or to scrutinise investment proposals ‘before the event’. The regime also appears to be too specific, encouraging debate around the legal interpretation of the Ordinance, takeover agreements and regulations, rather than on the economic merits of the rate cases being put forward. In particular:

– the framework was created with diesel-fuelled plant in mind; not alternative (capital-intensive) energy sources (see also section 2.3.3 below);

– the base rate has not changed since the 1980s in the case of TCU, and with only limited changes in the case of PPC. This has resulted in significant power cost adjustments, which have become larger and more volatile as fuel costs have increased over time. There is perhaps room to update the base rates to incorporate a more realistic assumption on fuel prices;

– the generation fuel-burn efficiency factor used in the fuel cost adjustment (0.08) has not changed since 1986, even though fuel-burn efficiency has improved. This, in effect, rewards the companies with additional profits as fuel prices rise;

– the (nominal) return on capital numbers of 15% (TCU) and 17.5% (Fortis TCI), often quoted by the companies, are out of date, and, in any case, the status of these parameters remains unclear.

The companies both noted that, not only have the base rates remained largely unchanged since takeover, but they have not even been increased for inflation, as they are set in nominal terms. Historically, the fuel cost adjustment, plus the historical demand growth in TCI, made this somewhat less problematic, but it is now much more of an issue.

2.3.3 Energy policy and the promotion of alternative energy sources

A number of stakeholders voiced concern over the lack of development of alternative energy sources. In particular:

– there is limited understanding as to why there has not been more progress in exploiting apparently abundant solar and wind energy resources;

– a number of users are frustrated with the existing ban on self-generation and feed-in tariffs, and wish to explore these opportunities;

– TCU has undertaken several studies of wind generation, and is frustrated over land and planning regulations, which have stalled initiatives on many occasions.

As regards the TCI Government energy policy overall, it is not clear to stakeholders what the likely future developments will be. Although the March 2011 Castalia report provides a starting point,[30] there has been no stand-alone statement by the TCI Government about its energy policy. The potential implementation of a carbon tax has also been questioned by a

[30] Castalia (2011), op. cit., March 31st.

number of stakeholders, on the grounds that it would ultimately be passed through to users, and would not provide the intended incentive effects.

2.3.4 Companies' perceptions of the risks and opportunities of regulatory reform

Separately, both Fortis TCI and TCU expressed their view that the regulatory system needs to become more transparent, independent and predictable. Both companies also attach great importance to retaining their existing licences and takeover agreement terms, in particular their duration and exclusivity.

The main opportunities for reform identified by the companies are as follows:

– reform of the fuel cost adjustment mechanism to achieve greater transparency, while retaining the principle that fuel costs should be passed through to consumers;
– reconsideration of the allowed rate of return (see section 2.2.3), provided that this reflects the costs and risks of providing electricity services in TCI;
– stronger regulatory incentives applied to controllable costs;
– enhanced transparency through greater information provision; and
– implementation of feed-in tariffs for renewable generation—these were welcomed, in particular by TCU, so long as they are incentivised by recognising only the avoided costs of the incumbent operator.

In addition, Fortis TCI highlighted that a rebalancing of tariffs across customer groups could be beneficial. TCU noted that deployment of renewable generation technologies could be a useful way to reduce dependence on diesel, and thereby act as a hedge against long-term oil price rises.

2.4 Summary

The current system of regulation on TCI centres on the process for rate-setting, as laid down in the Ordinance. While there are provisions for a rate review, these have been rare. Indeed, TCU's base-rate tariffs have remained unchanged in nominal terms since takeover in 1986. The companies are, however, protected from fuel price increases through the fuel cost adjustment, which has become a growing element of overall bills. Historically, this adjustment, plus the historical demand growth in TCI, made the fact that base rates had remained largely unchanged somewhat less problematic, but that this is now much more of an issue.

However, it is not clear that the regime has historically generated adequate incentives for the companies to operate or invest efficiently, or that it will do so going forward. The companies do not need to seek approval (from the government or Electricity Commissioner) *before* undertaking investments. They also *expect* that, should their returns dip below 17.5% (Fortis TCI) or 15% (TCU), the base rates will be revised upwards to recover any cumulative shortfall. The TCI Government and companies disagree on what the current regime *is*, leading to annual disputes. The companies note that the current system of regulation is not truly independent, since the Governor has the ultimate discretion in each year over whether to approve changes in tariffs, and this perceived politicisation of regulation may also harm incentives.

At the centre of any regulatory regime should be concern for the consumer. It is not clear that this is the case. Consumers do not understand their bills, the fuel cost adjustment, or what the current system of regulation allows for; and they do not think that the companies are empathetic towards them. Consumers have expressed concern that rising electricity bills are becoming unaffordable. They do not understand why renewable energy has not been developed. At the same time, consumers have praised the companies for their reliability and for their prompt response in times of emergency.

The companies are prepared to embrace changes to the current regime, so long as this makes it more transparent, independent and predictable. This includes changes to incentives for efficiency, and a regulatory regime that incentivises renewable energy. At the same time, the companies note that their licences should be protected, and that fuel costs should continue to be passed through (in some form) to customers.

3 Tariffs, cost drivers and operating performance

This section presents evidence on the level of electricity tariffs in TCI compared with other Caribbean jurisdictions, and highlights possible drivers of the observed regional differences in tariffs. It also compares the TCI electricity companies with other regional comparators along a number of dimensions relevant to assessing operating efficiency. Lastly, this section gives an overview of the cost structures of Fortis TCI and TCU.

The relevance of this section to the regulatory review and the design of an appropriate regulatory framework relates to whether existing tariffs are likely to reflect the cost of service provision of an efficient company facing operating conditions similar to those present in TCI. For example, to the extent that a company was inefficient (after taking into account the operating conditions in TCI), it would be expected to be able to reduce costs without impairing output, quality of service, or investment over the long term. It would also be reasonable for the regulator to reduce tariffs.

Alternatively, tariffs may be lower than the efficient level of costs. This would imply that tariffs may need to rise to enable the company to deliver the desired level of output, quality of service, and investment in a sustainable way. Yet another possibility is that tariffs are below the efficient level of costs and that the company is simultaneously inefficient, in which case it might be reasonable to offset any potential tariff increase against the company's efficiency improvements. Section 3.4 summarises the implications of the analysis presented in this section for potential efficiency improvements and tariff impacts.

Even though an inefficient company may have the ability to reduce costs without detriment to consumers, it is important that the regulatory regime also provides the incentive for the company to implement the initiatives necessary to achieve greater efficiency. The analysis presented in this section has therefore provided an important input to the design of the regulatory reform proposals and recommendations presented in sections 5 and 6.

While the analysis presented in this section has been adequate for the design of the regulatory framework, additional analysis is likely to be required in order to estimate efficiency targets for individual firms (examples of such analysis are given in section 6).

3.1 TCI tariffs and regional comparisons

3.1.1 TCI tariffs

Fortis TCI and TCU bill their electricity customers monthly, based on remote electronic meter reads of actual consumption (in kWh). The tariff rates in these bills comprise a base rate and a fuel cost adjustment (both in $/kWh).[31] The base rates and fuel cost adjustments charged by the two companies vary, reflecting the fact that they serve different customers on separate islands, and each company has its own electricity infrastructure (see Tables 3.1 and 3.2 below). For each company, the base-rate tariffs differ by customer class, but the fuel cost adjustment is a flat rate.

[31] There is no fixed monthly standing charge in the tariffs, and, for each type of user, there are no declining (or rising) blocks in the $/kWh charges levied.

Table 3.1 Current TCU base rates (Grand Turk and Salt Cay)

Customer class	Base rate ($US/kWh)
Residential premises	0.273
Non-residential premises	0.323
Official premises	0.273
Street lighting	0.273

Source: Ajodhia, V. (2011), 'Report of the Commissioner of Inquiry into the Variation of Tariff Rates', August 29th.

Table 3.2 Current Fortis TCI base rates (PPC area. ie, excluding South Caicos)

		Base rate ($US/kWh)			
Customer class	Consumption criteria (kWh pa)	Providenciales	North Caicos	Middle Caicos	Pine Cay
Residential		0.260	0.260	0.260	
Commercial & government		0.270	0.270	0.270	
Small-medium hotels and supermarkets	>240,000	0.250	0.250	0.250	0.250
Large supermarket	>240,000	0.250	0.250	0.250	0.250
Club Med		0.175			
Large hotel[1]	>3,200,000	0.170			
		Peak	Off-peak	Overall effective	
Water company		0.210	0.150	0.172	
		$US/month/ light	$US/KWh		
Street lights		20	0.230		

Note: This rate applies to The Bay Hotel and Resort (Beaches), The Palms, and Caicos Resorts Ltd (Amanyara). Source: PPC annual tariff submission 2009: Summary of rates; Schedule 8 revenue forecast. Fortis TCI rate review request August 2011 (existing rates).

When the system of base rates was first established in 1986,[32] Oxera understands that the intention was that this element of charges would remunerate both the ongoing operating expenditure (OPEX) and CAPEX incurred by the company. Importantly, the base rate adopted in 1987 included an allowance for the fuel purchasing cost, which was assumed to be $0.90/gallon of diesel for PPC and $1.00/gallon for TCU.

The implicit rationale for having a system of base-rate tariffs and fuel cost adjustments is that diesel fuel costs are largely deemed to be beyond the companies' control. These costs form a large component of the companies' total costs, and can be volatile. The fuel cost adjustment allows the risk of fuel price changes to be borne by customers rather than the companies, by enabling Fortis TCI and TCU to increase billing amounts when the cost of diesel exceeds that included in the base rate.[33] Box 3.1 summarises how the fuel cost adjustment works.

[32] The base rates for PPC and TCU were first set out in the Electricity Ordinance (as revised 1998). See Electricity rates and charges regulations (Grand Turk, Salt Cay and South Caicos), Section 32, Legal notice 52 of 1986; and Electricity rates and charges regulations (Providenciales), Section 32, Legal notice 5 of 1987.

[33] In the update of the Electricity Ordinance (May 15th 1998), the benchmarks were set at $1.40 per gallon for Grand Turk and Salt Cay, $0.80 for South Caicos and $0.90 for Providenciales. Under a revision of the Electricity Rates and Charges regulation

Box 3.1 Description of the cost adjustment

- **Actual fuel costs, A**—in any one month, the actual cost of diesel fuel purchased by Fortis TCI, and by TCU, is calculated, as a weighted cost in $/gallon. This excludes fuel used for vehicles and for other non-generation purposes. Call this '$A/gallon'.
- **Assumed fuel costs, R**—in any one month, however, the base rate assumes a weighted cost of diesel of $0.90/gallon in the case of Fortis TCI ($1.00/gallon in the case of TCU). Call this '$R/gallon'.
- **Difference (A minus R)**—where a difference exists between actual diesel purchasing costs, A, and the assumed purchasing costs in the base rate, R, the electricity company concerned is permitted to pass this additional cost on to customers. To calculate the required pass-through, it is necessary to convert the additional cost of diesel (A minus R) into an impact on the price of electricity per kWh.
- **Fuel-burn efficiency (f)**—in practice, the impact of the additional cost of diesel (A minus R) on the price of electricity will depend on the rate at which the electricity company is assumed to convert each gallon of diesel burned into 1kWh of electricity—ie, the level of fuel-burn efficiency. The fuel cost adjustment assumes a fuel-burn efficiency factor (f) of 0.08, or that every additional $1/gallon of fuel over the base rate means that the utility can charge customers an additional $0.08/kWh.
- **Fuel cost adjustment**—the fuel cost adjustment is listed on customer bills as a separate additional charge to the base rate (in $/kWh), and is calculated as f*(A minus R). The adjustment is applied equally to the different customer classes listed in the base rate.

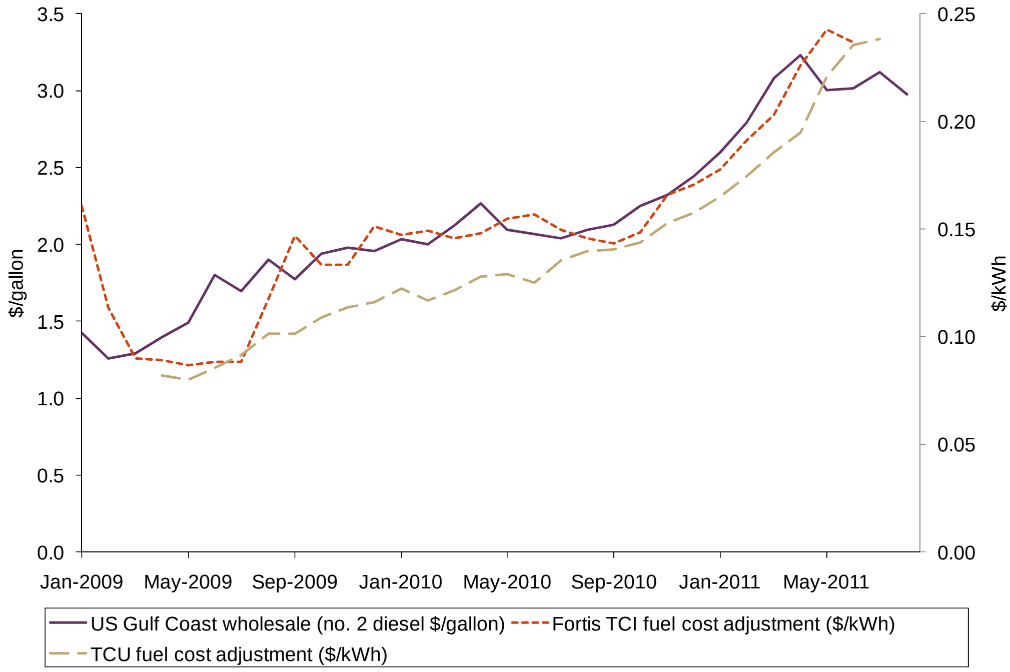
Source: Oxera, based on the Ordinance and on the fuel cost adjustment reports prepared by Fortis TCI and TCU and submitted to the Electricity Commissioner.

Changing the fuel cost assumption embedded in the base rate attenuates the degree of volatility in customers' (monthly) electricity bills. Also, as fuel costs have increased significantly in nominal terms since 1987, driven by changes in oil prices and refining margins, whereas the base rate has remained more or less constant in nominal terms and has therefore assumed a fuel price that is falling in real terms, the fuel cost *adjustment* has naturally come to represent an increasing proportion of customers' bills. With the adjustment now in the band $0.20–$0.25/kWh, it will make up around 50% of a bill (or more, for those with discounted base rates).

Figure 3.1 below illustrates how fuel cost adjustments charged by Fortis TCI and TCU correlate with the costs of diesel. The figure also shows that the fuel cost adjustment is generally lower for TCU than for Fortis TCI. This is partly due to the slightly higher fuel cost purchasing assumption embedded in TCU's base-rate tariffs. The figure also shows that changes in the fuel cost adjustments lag changes in wholesale prices, although Fortis TCI's lag is somewhat shorter than TCU's. The fuel cost adjustment of Fortis TCI is also somewhat more volatile than for TCU. These features may partly be explained by the fact that TCU has greater diesel storage capacity.

as applied to Grand Turk, Salt Cay and South Caicos in 1999, the fuel benchmark for Grand Turk and Salt Cay was reduced from $1.40 to $1.00.

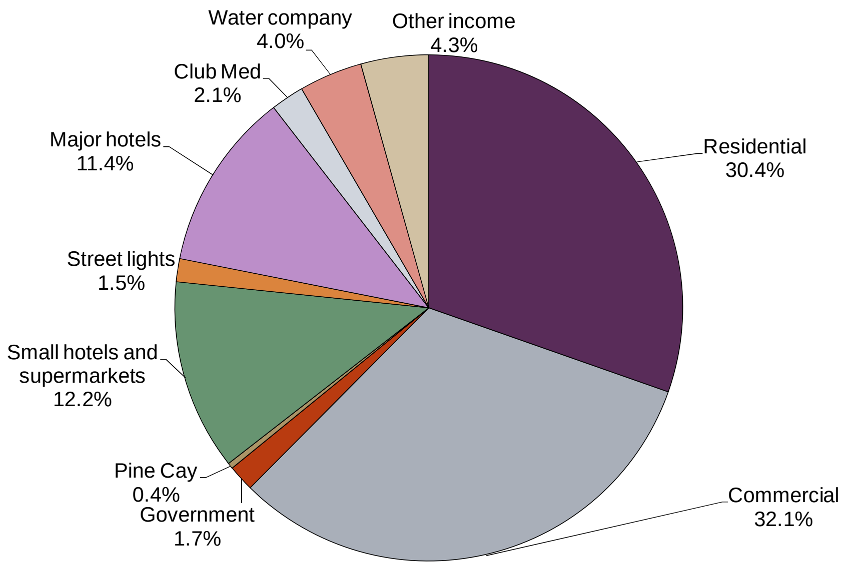
Figure 3.1 Wholesale Gulf Coast diesel costs versus TCI residential tariffs



Source: Fuel cost submissions to the TCI Government; further information from the TCI Government; and Datastream.

Figure 3.2 shows the resulting share of revenues, for Fortis TCI, accounted for by each customer class. This illustrates that, at the prevailing charges, the largest single source of revenue on Providenciales is from commercial customers, closely followed by residential customers.

Figure 3.2 Share of revenues for Fortis TCI (PPC area) by customer class



Source: Schedule 5.0 of PPC Regulatory filing (2010), 'Operational income'.

In discussions with stakeholders, Oxera invited various businesses to comment on the proportion of their operating costs accounted for by electricity bills. Three hotels responded (see Table 3.3). Movements in these figures over time may be partly explained by movements in the fuel cost adjustment. The impact of the discount on operating costs, offered by Fortis TCI to the larger hotels, is also visible.

Table 3.3 Comparison of annual electricity costs as a percentage of operating costs

	2008	2009	2010	2011 (year to date)
Medium hotel	17.4%	13.6%	15.2%	17.4%
Larger hotel 1	8.9%	6.7%	7.3%	7.1%
Larger hotel 2	4.9%	4.9%	5.4%	6.0%

Source: Hotel and Tourism Association.

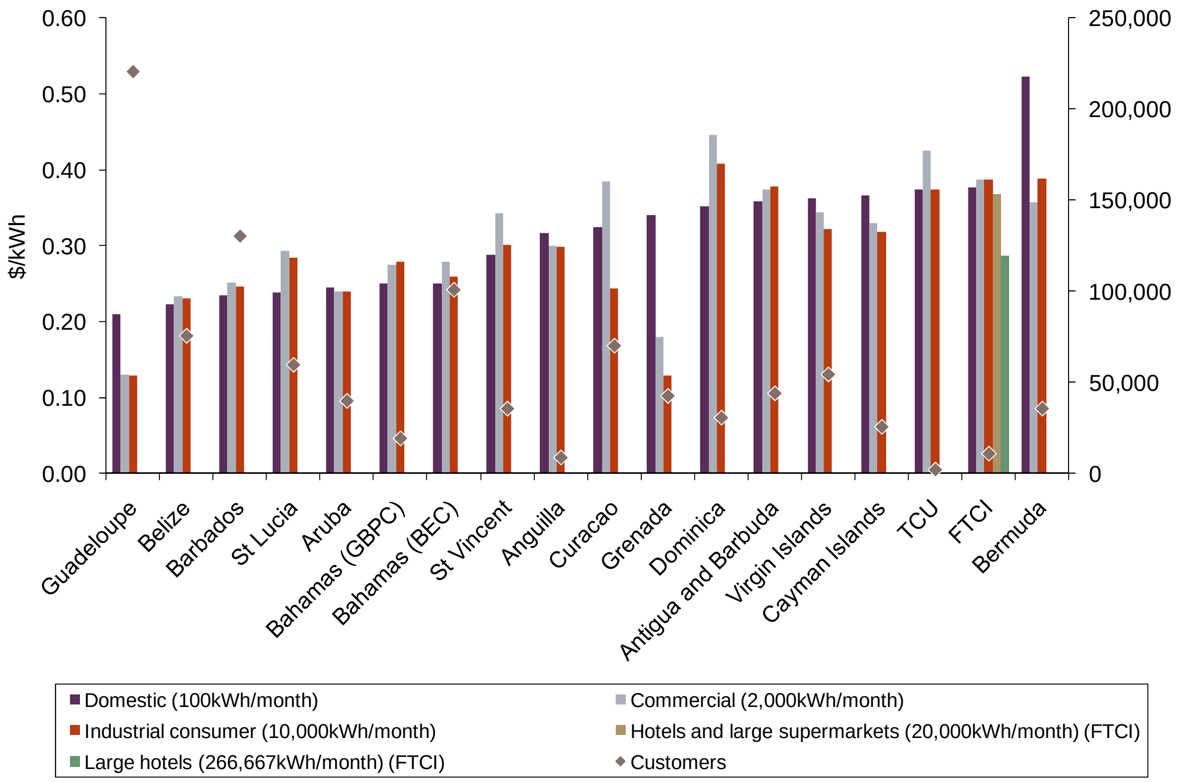
Smaller commercial customers commented on how high electricity costs were as a proportion of their own outgoings, although figures were not provided. Similarly, residential customers also commented on how much electricity bills were as a percentage of their income (although, again, figures were not provided).

The average bill for a residential consumer on Providenciales in 2010 was $147 per month, and for the average commercial customer $920 per month.[34]

3.1.2 Regional tariff comparisons

Figure 3.3 below compares the electricity bills charged in TCI with those in other Caribbean jurisdictions. This is presented in ascending order of the total effective $/kWh rate charged to domestic consumers (including base rates and any fuel cost adjustments). Charges to other customer classes are also shown, along with the number of customers served in each jurisdiction.

Figure 3.3 Tariffs ordered by residential tariffs



Source: Caribbean Electric Utility Service Corporation (CARILEC) (2010), 'Benchmarking study' data for different tariff categories over the year 2009. Information for Jamaica and Trinidad & Tobago, presented in the CARILEC study, is excluded from the figure for exposition purposes, since both have significantly higher customer numbers. As Fortis TCI tariff data was not presented in the CARILEC study, Oxera data is presented for the purposes of this figure, by combining base-rate information with fuel cost adjustment data (taken from the regulatory monthly

[34] At average consumption levels for each customer type. Source: Fortis TCI (2010), 'Corporate scorecard'.

filings from January to December 2009). Additional customer categories have been included for Fortis TCI: the hotels/large supermarkets tariff (for customers using more than 240,000kWh per year) and the large hotel tariff (for customers using more than 3,200,000kWh per year).

Figure 3.3 highlights that:

– the residential tariffs charged by TCU and Fortis TCI are among the highest in the Caribbean, although Bermuda has the highest residential tariffs;
– tariffs tend to be lower in larger jurisdictions (ie, those with more customers), and TCI has the smallest customer base in the sample;
– in practice, electricity companies in the Caribbean frequently charge lower rates to residential customers than commercial customers (there are some notable exceptions—eg, Guadalupe, Grenada and Bermuda);
– in some jurisdictions, tariffs to larger industrial users are lower than other commercial customers with somewhat lower overall consumption.[35]

It is also worth noting that many jurisdictions apply separate base rates and fuel cost adjustments, albeit with differing assumptions on fuel costs included in the base rate versus the adjustment factor.[36]

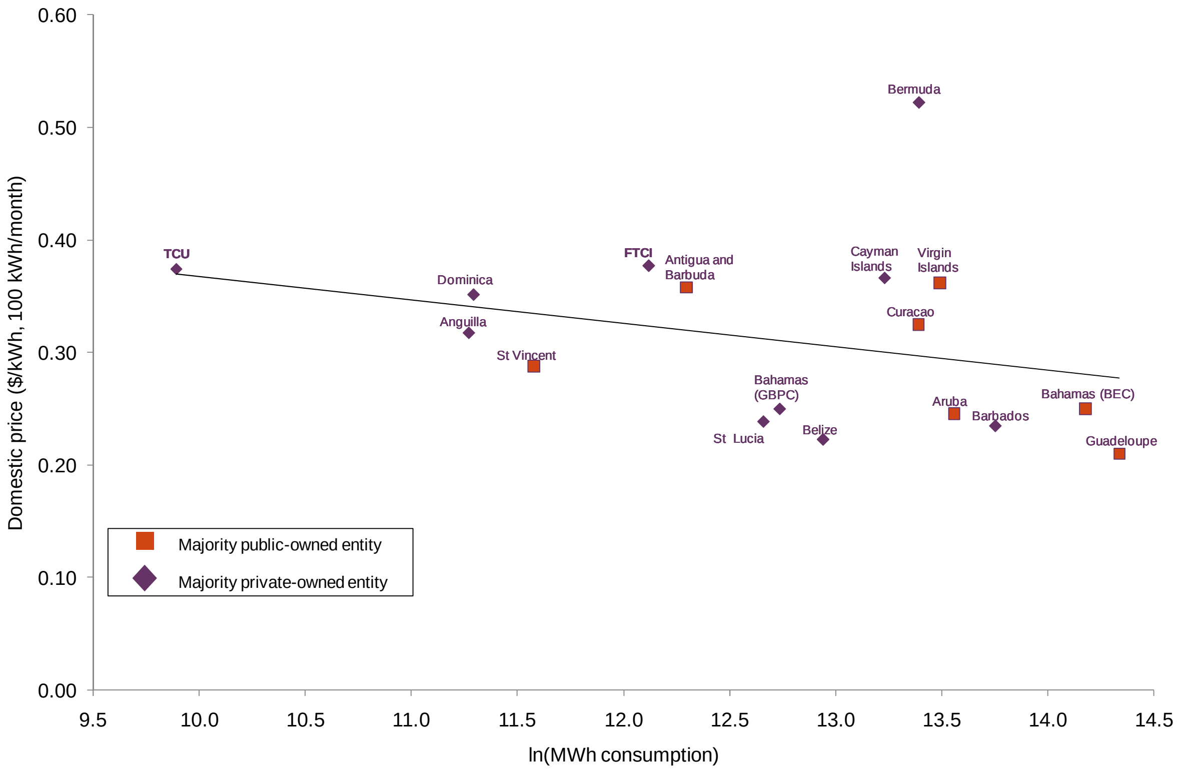
As noted above, larger jurisdictions appear to have generally lower tariffs than smaller jurisdictions. Figure 3.4 further illustrates the correlation between the size of the customer base and residential tariffs. The figure indicates that there are 'economies of scale' in the provision of electricity.[37] For this reason, lower tariffs for larger customers within a given jurisdiction, or for customers located in larger jurisdictions, could be cost-reflective in principle (see section 3.2 for further discussion).

[35] For example, as CARILEC (2010) notes: 'Average rates decline for higher consumptions within the same consumer class. When compared in terms of average ¢ per kWh charged to consumers, the highest rates are for commercial consumption, while industrial consumption has the lowest rates. This seems to indicate a rate policy to support industry development with the contribution of commercial consumers, mostly tourist facilities.' CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

[36] This is evident from summary information on tariff structures presented in CARILEC (2010), 'CARILEC Tariff Survey Among Member Electric Utilities – Mid-Year (June) 2010'.

[37] 'Economies of scale' refer to a falling cost per unit as additional units are supplied.

Figure 3.4 Residential tariffs versus consumption (log scale)



Note: When data covers a large range of values, it is typically presented on a logarithmic scale (specifically, the natural logarithm). The use of the natural logarithm scale to compare tariffs by consumption is consistent with the treatment in Jha, A.K. (2005), 'Institutions, Performance, and the Financing of Infrastructure Services in the Caribbean', World Bank Working Paper no. 58.
Source: Price and consumption data is taken from CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

3.2 Analysis of cost drivers

3.2.1 Cost drivers in Caribbean electricity provision

Caribbean jurisdictions face a number of common factors that affect the costs of electricity provision:[38]

> [the Caribbean islands] are isolated systems with no or very limited possibilities for interconnection. This requires high reserve capacity margins in order to dispose of sufficient generation availability for maintaining sufficient reliability of supply…Due to the small size of island systems, there are no economies of scale to be exploited while dependency on oil supply is high. Being small also leads to higher prices for inputs as bulk purchase is limited. Such factors tend to lead to higher costs and consequently, higher electricity prices.

At the same time, there is wide diversity in their operating environments. In this sense, they are 'the same but different':[39]

> [The differences between Caribbean jurisdictions] relate to the size of each individual Island as measured in the area size, peak load, energy consumption, etc. as well as in the economic characteristics such as GDP per capita and economic growth. Furthermore, there are geographical differences which result in differences in power system configuration (eg, voltage level choice) as well as possibilities for installing

[38] CARILEC (2008), 'Position Paper on Energy Policy', January.
[39] CARILEC (2008), 'Position Paper on Energy Policy', January.

> renewable generation. Finally, there are institutional differences such as type of utility ownership and presence of regulatory bodies.

Caribbean jurisdictions also tend to be exposed to difficult weather conditions, notably:[40]

> [a] salty and corrosive environment, whose effects are reinforced by prevailing wind directions, and the occurrence of phenomena like hurricanes, droughts and floods, that impose on the electrical systems special conditions for their design, operation and maintenance.

CARILEC notes that, in general across the Caribbean, the performance of electricity companies has improved over time and is generally satisfactory.[41] That said, it also notes that differences in performance between electricity companies can:[42]

> *partly* be explained by differences in the characteristics of the systems beyond the control of utilities like somewhat more economy of scale at the larger utilities, customer base, load density and demand composition. [emphasis added]

The above discussion indicates several valid reasons why the costs of providing electricity in TCI could be different to those in larger or more developed markets elsewhere in the Caribbean or in other regions.

Based on a review of the available literature, the factors that could affect the performance of an electricity utility in any Caribbean jurisdiction would appear to be as follows (note that these are not mutually exclusive):[43]

– **scale**—the size of each jurisdiction in terms of installed capacity, load, and number of customers served;
– **remoteness**—the distance of the jurisdiction from established fuel trade routes and trading hubs, or interconnection possibilities;
– **accessibility of ports**—whether harbour facilities make it easy to transfer fuel in bulk to the jurisdiction, or to choose alternative fuels (eg, diesel versus coal);
– **load density**—the extent to which the jurisdiction comprises discrete populations on separate islands, or the majority of its population on one main island;
– **weather and climate**—the extent to which the jurisdiction is exposed to adverse salinity, flooding and weather events (tropical storms and hurricanes), and to favourable weather conditions that are conducive to renewables (eg, wind, solar);
– **scope for fuel storage**—which in turn is affected by the size of the island's jurisdiction and availability of land for bulk fuel storage (versus other uses);
– **demand growth and customer composition**—whether demand in the jurisdiction is growing over time (which, for example, could enable fixed costs to be spread across a wider customer base). The mixture of customer types served (eg, hotels versus residential), and the resultant level of peak demand;
– **availability and feasibility of alternative sources**—for example, diesel versus natural gas, or diesel versus renewable energy (eg, wind, solar, geothermal);

[40] See CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September. Arguably, however, some jurisdictions will be more prone to severe weather than others. For example, within TCI, Grand Turk is more exposed to storms from the Atlantic than Providenciales, as was evident from the after-effects of Hurricane Ike in 2008.

[41] See CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September, p. 2. 'Customer service rates are high compared with international figures; sufficient generation reserves are found in most of the utilities in the region; generation availability is generally high indicating good maintenance practices; network and retail costs are reasonable considering system characteristics; and the reported levels of bad debt are not high'.

[42] See CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September, p. 2.

[43] See, in particular, Jha, A.K. (2005), 'Institutions, Performance, and the Financing of Infrastructure Services in the Caribbean', World Bank Working Paper no. 58; Gerner, F and Hansen, M. (2011), 'Caribbean Regional Electricity Supply Options. Toward Greater Security, Renewables and Resilience', The International Bank for Reconstruction and Development/The World Bank; Nexant (2010), 'Caribbean Regional Electricity Generation, Interconnection, and Fuels Supply Strategy', Final Report, submitted to The World Bank; CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September, p. 2; and CARILEC (2008), 'Position Paper on Energy Policy', January.

– **the institutional, regulatory, and legal framework**—whether the utility is privately or publicly owned, whether tariffs are subsidised, and whether the regulatory framework provides adequate incentives for efficiency in undertaking operations and investment;
– **company management and efficiency**—the degree to which the management is incentivised and capable of delivering appropriate levels of service, efficient operations and investment at the right time, at the right cost, and in the right place.

3.2.2 Economies of scale

As suggested in Figure 3.4, scale could be considered an important driver of the costs of providing electricity.[44] As such, electricity businesses operating in larger jurisdictions would be expected to have lower costs (and hence tariffs) than those operating in smaller jurisdictions. Economies of scale could be present in the electricity sector for a number of reasons, including the following.

– **Enhanced plant mix**—a larger scale generally increases the options for generation plant that can be used at utility scale. Diesel plant are generally the most expensive type of fossil-fuel plant to run (they are at the high end of a typical utility merit order), but can be more efficient at a small scale, and alternatives may not be feasible.

– **Scope for interconnection**—a larger scale increases the feasibility of interconnecting generating sets and customers by establishing an integrated transmission and distribution grid. This can be used to optimise the system, and can reduce the capacity margins required (see next bullet point).

– **Lower reserve capacity**—since a larger scale means both more generating units (or a greater range of generation options), and more scope for interconnection (as noted above), a larger electricity undertaking generally needs less reserve capacity (measured as a proportion of average demand) on standby to deal with periods of peak demand (‘reserve capacity margin’). In effect, scale delivers a diversification benefit to deal with periods of peak demand.

– **Spreading fixed overheads**—the provision of electricity involves a series of fixed capital and operating costs (eg, administration, overheads) to a business that, over a certain range, do not vary with load or customers served. For a larger electricity undertaking, these fixed costs can be spread across a wider customer base, resulting in lower costs per customer served.

– **Better procurement**—scale can also deliver an element of choice and buyer power for the electricity business in sourcing fuel, other consumables, and capital equipment. While centralising procurement at the parent-company level (where an electricity business is owned by a company spanning multiple jurisdictions) might assist, costs and procurement strength will still be determined by the physical realities of importing fuel to where it is needed, and by the resultant scale and frequency of fuel purchases.

Given that scale is a main driver of the costs of electricity provision, Table 3.4 ranks Caribbean electricity providers across several jurisdictions according to various scale measures.[45]

[44] In larger jurisdictions, there may be a point at which economies of scale are exhausted. However, in the Caribbean context, jurisdictions are typically of a size whereby higher demand can mean lower unit costs.
[45] See CARILEC (2010), ‘Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009’, draft report, September, p. 2.

Table 3.4 Ranking of entities by various scale measures (in ascending order of scale)

Rank	Customer numbers	Installed capacity (MW)	Number of employees (full-time equivalent)	Average consumption per month (MWh)
1	**TCU**	**TCU**	**TCU**	**TCU**
2	Anguilla	Anguilla	Nevis	Anguilla
3	**Fortis TCI**	Belize	**Fortis TCI**	Dominica
4	Bahamas (GBPC)	Dominica	Anguilla	St Vincent
5	Grand Cayman	St Vincent	WEBAruba	**Fortis TCI**
6	Dominica	Grenada	St Kitts	Antigua and Barbuda
7	St Vincent	**Fortis TCI**	Aruba	St Lucia
8	Bermuda	St Lucia	Bahamas (GBPC)	Bahamas (GBPC)
9	Aruba	Antigua and Barbuda	Grand Cayman	Belize
10	Grenada	Grand Cayman	Antigua and Barbuda	Grand Cayman

Source: Analysis of CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

As shown above, Fortis TCI and TCU are among the smaller electricity providers in the region when measured by customer numbers, employees, and total installed generation capacity—indeed, on some measures, TCU is the smallest provider in the sample. Fortis TCI is the third-smallest provider, as measured by customer numbers, but is only the seventh smallest in the sample in terms of installed generation capacity (52.9 MW in 2009).

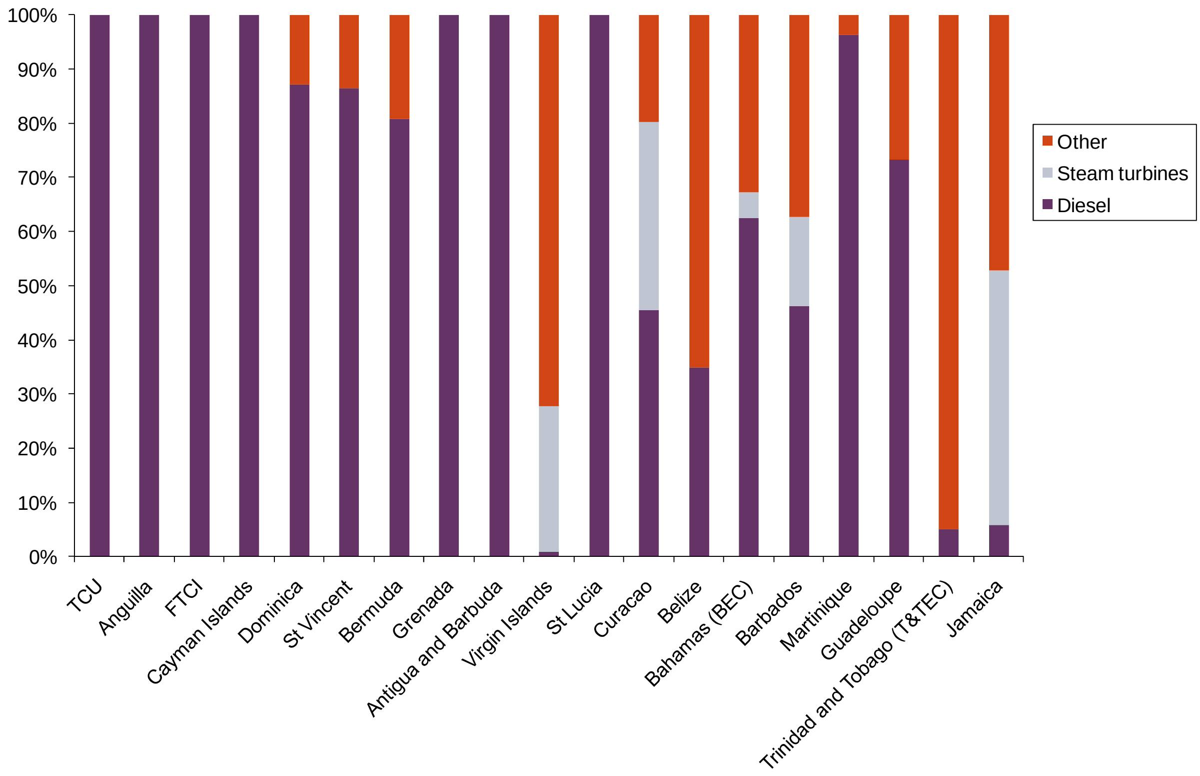
To understand how the performance of Fortis TCI and TCU may be affected by the scale of their operations, it is useful to consider plant mix, capacity margins (and related measures), fuel costs, and labour productivity. The first two relate to CAPEX and investments in fixed assets, and the last two concern OPEX, as discussed next.

Plant mix

Both Fortis TCI and TCU rely exclusively on diesel plant for electricity generation—specifically no. 2 diesel. While other generation technologies based around fuels other than diesel may be less costly, and their prices possibly less correlated with movements in the oil price over the long term, there are likely to be constraints on the ability of Fortis TCI and TCU to adopt other generation technologies and fuels. This is demonstrated in Figure 3.5, which presents the plant mix in Caribbean jurisdictions in ascending order of customer numbers served. The point to note from this figure is that the smallest jurisdictions—including TCI (as served by Fortis TCI and TCU), Anguilla and the Cayman Islands—use diesel plant for 100% of their generation needs, whereas the larger ones (eg, Dominica, St Vincent and Bermuda) appear to have a more diverse generation mix.[46] This suggests that reliance on diesel generation in TCI could be efficient, and it is interesting to note that all jurisdictions in the sample use diesel generators (typically low- and medium-speed diesel generating units) to some extent.

[46] This is also illustrated through an independent analysis conducted by Nexant (2010), 'Caribbean Regional Electricity Generation, Interconnection, and Fuels Supply Strategy', Final Report, submitted to The World Bank

Figure 3.5 Plant mix adopted (in ascending order of customers)



Note: 'Other' refers to hydro generation (used in Dominica, Guadeloupe, Jamaica and St Vincent & the Grenadines); wind and solar (used in Curacao, Guadeloupe and Martinique); and geothermal (used in Guadeloupe). Greater utilisation of these alternative energy sources is highly dependent on the natural resources of individual countries.
Source: CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

As a fuel for generating electricity, diesel tends to be more expensive than other fossil fuels such as heavy fuel oil (HFO), and, in some cases, it may be possible to lower generation costs by using HFO in (low-speed) diesel generating units.[47] However, it is unclear whether it would be advantageous or possible to increase the use of HFO in TCI. In general, for HFO, the size of generating units used is much larger than for no. 2 diesel.[48] Furthermore, it is noteworthy that a number of other jurisdictions in the Caribbean are seeking to phase out HFO due to its environmental impact, and there would be problems in finding appropriate sites in TCI, where it is even more difficult to situate generation plant away from the population.[49]

Unlike some other larger Caribbean jurisdictions, TCI does not benefit from indigenous supplies of alternative fossil fuels. In contrast, Trinidad & Tobago, a very large jurisdiction, has access to cheap indigenous natural gas reserves. In addition, TCI does not have a geography that lends itself to hydro power. This can be contrasted to some other small islands, such as Dominica (which is currently exploring further how to exploit its hydro resources)[50] and St Vincent & the Grenadines.

Coal, which 'on paper' is a cheaper fuel than no. 2 diesel, is not used extensively in the Caribbean, although it is used in the Dominican Republic. However, coal requires larger

[47] See Jha, A.K. (2005), 'Institutions, Performance, and the Financing of Infrastructure Services in the Caribbean', World Bank Working Paper no. 58

[48] See, for example, Castalia (2011), op. cit., p. 20.

[49] Gerner and Hansen (2011), op. cit., p. 10.

[50] See Nexant (2010), op. cit.

generation sets and, in order to be economical to import, requires a high frequency of purchases and deep ports. Even then, the environmental impacts on local air pollution (and global CO_2 emissions) need to be taken into account. Taken together, coal is much less suited to small Caribbean islands, such as TCI, since it is far less economical to import in small volumes, is unsuited to small-scale generation, and raises environmental concerns.[51]

The points raised in this section relating to plant mix suggest a number of key drivers for the existing configuration of Fortis TCI's and TCU's generation assets, which helps to explain in part why TCI electricity tariffs are high compared with those in other Caribbean jurisdictions. In particular, TCI is a small and remote grouping of islands, with a relatively small population and low overall demand for electricity.

Other small island states can seek to create scale economies when there are enough islands clustered together. For example, they may benefit from access to existing bulk-fuel freighting routes, or future interconnection possibilities with neighbouring islands. However, it is the remoteness of TCI that causes problems here. TCI does not lie on a bulk-fuel freighting route; rather, diesel arrives indirectly, via the Bahamas, in small barges, having incurred taxes and handling charges levied on route. As regards future interconnection opportunities, while interconnection initiatives are currently being considered in the Eastern Caribbean, the islands there are in fairly close proximity. Such initiatives are less likely to be viable for TCI, which, as noted, is both small *and* remote from other island states.[52]

The realistic future alternative to diesel on TCI would appear to be renewable energy (especially wind and solar) in combination with demand-side measures. However, encouraging renewables (while ensuring continued reliability in a small, non-interconnected system) is perhaps more challenging for TCI than for other Caribbean jurisdictions (large or small). Diesel is therefore likely to continue to play a (perhaps dominant) role in the energy mix for the foreseeable future.

Reserve capacity margins and other generation indicators

Reserve capacity margins measure the ratio of available capacity to the annual peak demand.[53] The margins must be sufficient to deal with peak demand and the failure of one or more generating sets in order to ensure the desired level of system reliability. All else being equal, a larger capacity margin will reduce the system-wide average utilisation of installed generation units and thereby increase electricity tariffs.

Reserve capacity margins required to ensure the desired system reliability are lower for interconnected and/or for large electricity systems.[54] This is because larger, more interconnected systems tend to have a larger number of more diverse generating plants, reducing the probability that outages will be experienced across all generating units simultaneously.

Figure 3.6 below compares the capacity margins of TCU and Fortis TCI to other Caribbean jurisdictions.[55] This is presented in order of customer numbers, to show the association between capacity margins and scale. Other indicators are also presented, including utilisation factors (which would be expected to be lower for systems with higher capacity

[51] Gerner and Hansen (2011), op. cit., pp. 11 and 20.

[52] Interconnection can help to encourage renewable energy and reduce diesel dependence, since this lessens the intermittency of renewables, and decreases reserve margin requirements across the system. Focusing on the Eastern Caribbean islands (plus the larger jurisdictions of Jamaica, the Dominican Republic and Haiti), Gerner and Hansen (2011), op cit., note that island states have traditionally considered single-island solutions for electricity, whereas multi-country solutions may be explored going forward. This could include greater use of submarine electrical interconnections between Eastern Caribbean islands, which, in turn, may also improve the prospects for large-scale renewable energy.

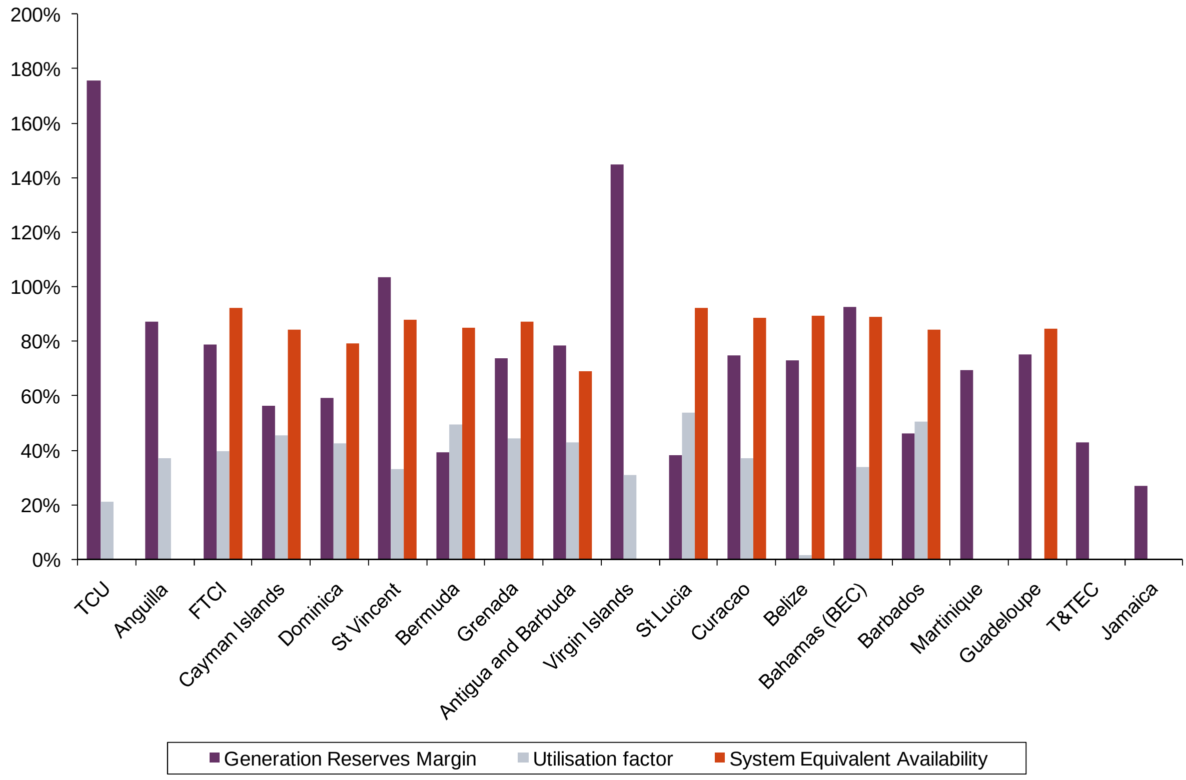
[53] Specifically, the ratio of capacity minus peak demand and peak demand.

[54] CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September, p. 63.

[55] Based on numbers provided in CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

margins), and system equivalent availability (which would be expected to be higher for systems with higher capacity margins).

Figure 3.6 Generation reserves margins (in ascending order of customer numbers)



Source: CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

Figure 3.6 shows that Fortis TCI's reserves margin in 2009 were similar to a number of larger jurisdictions in that year. In 2011, this is likely to have increased to around 130% in 2011 as a result of additional investment in capacity.[56] The figure also shows that TCU had a particularly large reserve capacity margin in 2009, and, because of this, sold one of its generation units in 2011.

Fuel purchasing costs

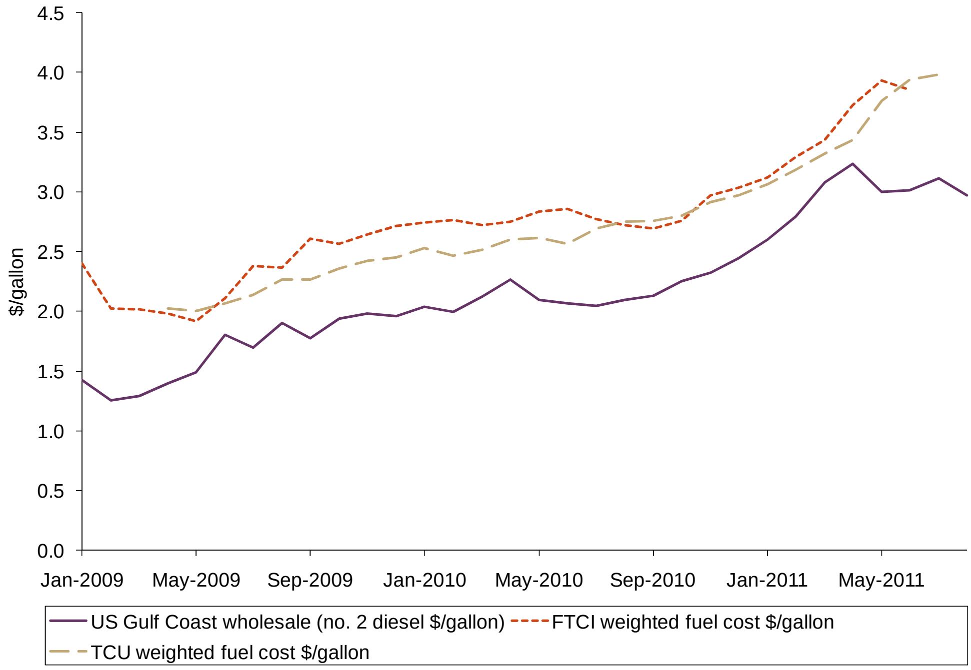
As discussed above, as both Fortis TCI and TCU rely exclusively on diesel plant, efficient procurement of fuel would be expected to be a key driver of the overall cost of electricity for TCI customers. For this reason it is important to note that both Fortis TCI and TCU are served by the same provider based in the Bahamas. Indeed, the seeming lack of competing providers and alternative supply routes, and limited port facilities and storage capacity (especially in Providenciales) suggest that the ability to adopt alternative fuel procurement strategies is also constrained.[57] In turn, this would suggest that the companies' ability to influence fuel purchasing costs is limited, and would highlight how the relatively small scale of the TCI electricity sector may be contributing to higher tariffs when compared with other Caribbean jurisdictions

[56] Based on a peak demand of around 31MW (see section 2.1) and installed capacity of around 71MW.

[57] The provider imports diesel to the Bahamas in bulk, some of which it transfers to smaller barges and transports by freight to TCI. In practice, this means that, in addition to the wholesale cost of diesel and the costs of bulk transportation to the Bahamas, further costs are incurred, including mooring and handling fees and stamp duties in the Bahamas, freight and insurance costs in forwarding the diesel to TCI, and a profit margin for the provider. Fortis TCI has noted that small barges are needed to bring in diesel owing to the lack of deep-water ports on Providenciales. This increases the frequency of diesel imports and reduces the company's procurement power, raising the overall cost of imported diesel. Fortis TCI also notes that few diesel providers are interested in serving the market. Source: Discussions with the companies, and examination of a recent oil purchasing invoice.

Figure 3.7 shows the actual purchasing costs of Fortis TCI and TCU compared with the typical wholesale cost of diesel over a period of two and a half years.

Figure 3.7 Fuel purchase costs on TCI versus wholesale costs, January 2009 to May 2011



Source: Fuel cost submissions to the TCI Government; further information from the TCI Government; and Datastream.

Interestingly, the fuel purchasing costs for TCU and Fortis TCI differ slightly, perhaps indicating differences in the terms reached with the diesel provider and the volumes purchased in any one month.

While the ability to influence unit fuel purchasing costs may be limited in practice, there may nevertheless be opportunities to improve efficiency in the conversion of fuel to electricity, and in minimising system losses in distribution. For example, comparing the diesel plant fuel efficiency and system losses of Fortis TCI (PPC area) and TCU with other Caribbean jurisdictions, Castalia highlighted the following.

– Fortis TCI is regarded as 'middle-ranking' on diesel plant fuel efficiency among Caribbean jurisdictions, even when compared with larger systems (which tend to be more fuel-efficient). This is also before the commissioning by Fortis TCI of its new, more fuel-efficient, Wartsilla plant. However, Castalia notes that system losses (including theft of electricity) are high compared with the other Caribbean jurisdictions examined.[58]

– TCU's diesel plant fuel efficiency ranks at the 'low end of the spectrum, although not by much'. Castalia notes that this demonstrates 'well-run operations even when compared with larger companies'. TCU's system losses are the lowest of the jurisdictions examined by Castalia.[59]

Arguably, the lower system losses faced by TCU compared with Fortis TCI demonstrate one of the benefits of small scale—a smaller network is less prone to losses from its distribution system, and it may be easier to detect and mitigate theft of electricity on a very small island.

[58] Castalia (2011), 'Development of an Energy Conservation Policy and Implementation Strategy for the Turks and Caicos Islands', final report prepared for the Government of the Turks and Caicos Islands, March 31st, p. 20.
[59] Ibid., p. 29.

Labour costs

An important reason why larger jurisdictions benefit from economies of scale is that overheads and other fixed costs can be more easily allocated to a larger number of customers or units sold, resulting in lower unit costs and potentially lower unit tariffs. Therefore, to compare the labour efficiency of Fortis TCI and TCU with other jurisdictions, it is useful to consider how the number of full-time equivalent employees (FTEs) varies with the overall number of customers and total electricity consumption.

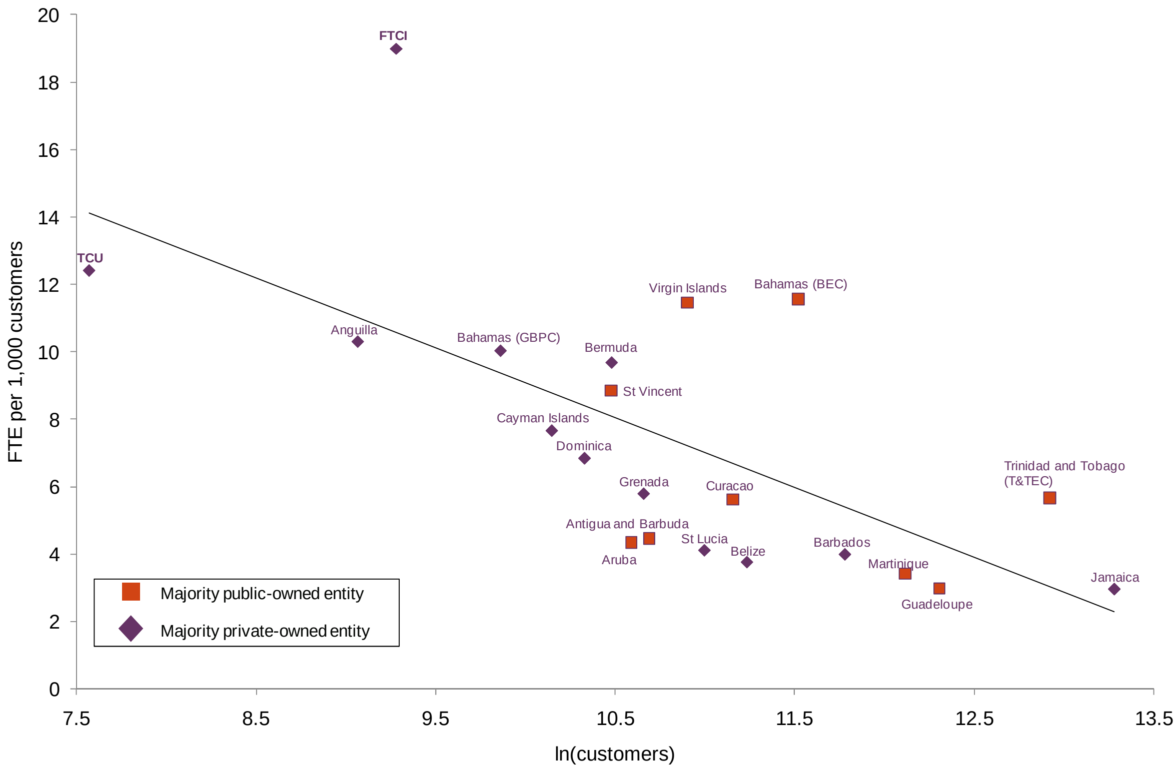
If economies of scale are likely to exist, FTE numbers per customer served would be expected to be lower for the larger electricity companies. In addition, at any given scale, some companies may be more efficient than others, and so they may have a lower employee-to-customer ratio than might be expected.

Moreover, given Fortis TCI's recent CAPEX programme, it might be expected to have improved its operating efficiency over recent years, including the reliability of its network (low standby and maintenance requirement), IT systems and remote metering. Similarly, TCU might be expected to have improved its efficiency since the replacement of its entire network following Hurricane Ike, and its high reliability.

On the first measure—FTE employees per customer—Figure 3.8 indicates that economies of scale are likely to be present. Electricity companies operating in larger jurisdictions, including Jamaica and Trinidad & Tobago, need to employ fewer staff per customer served than those operating in medium-sized jurisdictions (such as St Vincent), which in turn need to employ fewer staff per customer than those operating in the smallest of the jurisdictions (TCI and Anguilla).[60] This is consistent with the notion that, in order to serve any given customer base, a minimum stock of managerial and staff capacity is required to run the business and maintain the assets. It is also consistent with the idea that there are synergies in resource-sharing and deployment of staff across a business as it grows.

[60] The figure plots a line of best fit between the number of FTEs per customer and the natural logarithm of customer numbers. The line is downward-sloping, which could be consistent with the presence of economies of scale.

Figure 3.8 Labour productivity (number of FTEs per 1,000 customers) versus customers (log scale)



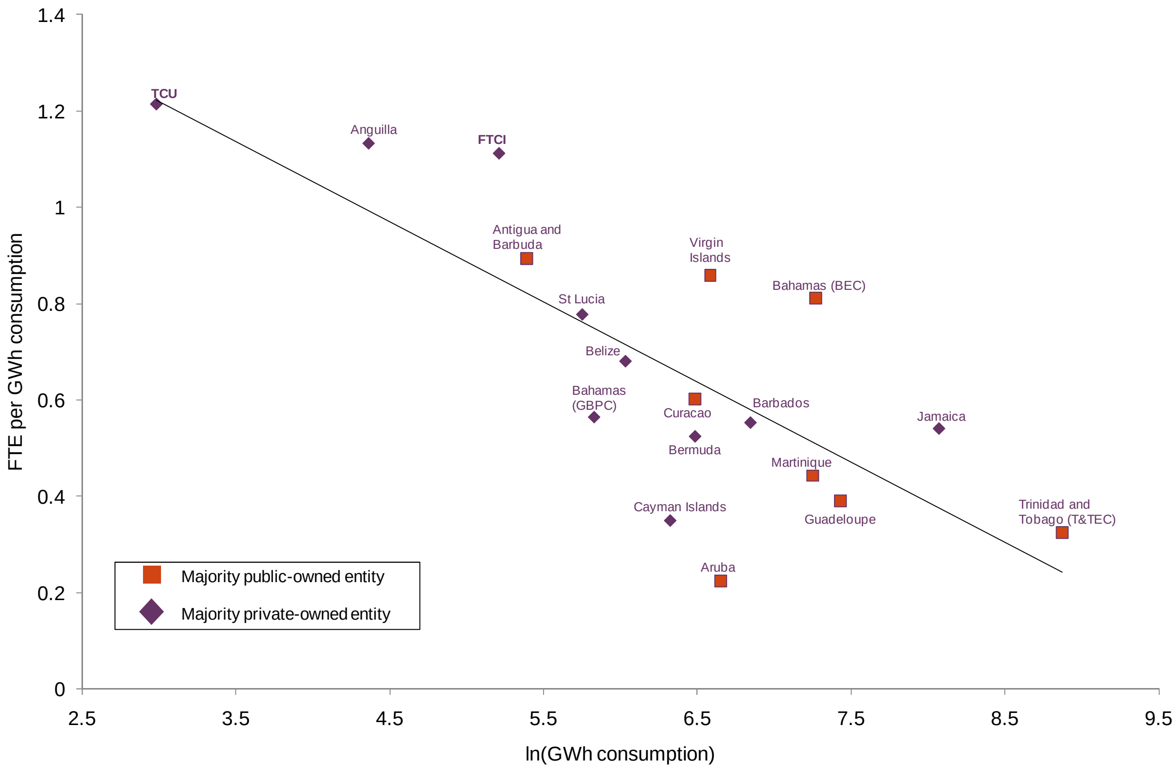
Note: When data covers a large range of values, it is typically presented on a logarithmic scale (specifically, the natural logarithm). Fortis TCI data includes both the PPC and AEP areas.
Source: CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

Figure 3.8 provides an indication that TCU could be above-average efficiency in the Caribbean, lying as it does below the fitted line. In contrast, Fortis TCI would appear to be inefficient relative to the average, lying as it does above the line of best fit, and so has a larger than predicted number of employees for its customer base.[61] This is despite TCU being significantly smaller than Fortis TCI. Relative to TCU, Fortis TCI would be expected to enjoy some economies of scale, and to have a lower number of FTEs per 1,000 customers than TCU, but this does not appear to be the case. Figure 3.8 would also indicate that both TCU and Fortis TCI could reduce their number of FTEs per customer served to achieve best practice (indicated by the collection of companies significantly below the fitted line).

On the second measure—scale in terms of GWh consumed—Figure 3.9 below indicates that, since TCU lies slightly above the fitted line, it could be around average efficiency (or perhaps slightly inefficient) relative to the average for the Caribbean, while Fortis TCI could be efficient relative to the average. (St Vincent and Dominica are outliers using this measure, so Figure 3.9 does not include these jurisdictions.)

[61] This analysis is at an indicative level only, not least since a number of other potentially relevant factors (in addition to scale) are excluded from the analysis.

Figure 3.9 Labour productivity (FTE per GWh consumed) versus consumption (GWh; log scale)



Note: When data covers a large range of values, it is typically presented on a logarithmic scale (specifically, the natural logarithm). This comparison excludes Dominica and St Vincent as they are outliers on the labour productivity measure and are not the subject of the current report. Fortis TCI data includes both the PPC and AEP areas.
Source: CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

The above analysis is indicative, and does not indicate the total factor productivity of either Fortis TCI or TCU.[62] That said, there are valid reasons for adopting the approach used, which potentially favours both Fortis TCI and TCU. For example, the comparisons are more robust than simply ranking companies according to the ratio of FTE employees to customers (which would fail to account for economies of scale).[63] The FTE numbers for Fortis TCI and TCU have also been adjusted downwards, relative to those reported in the 2010 CARILEC study.[64]

[62] The analyses exclude other potentially relevant industry variables in fitting the trend line, and exclude country-specific factors that drive costs and which cannot be easily captured. Different companies may report data in different ways. Other complementary techniques are available for creating cost functions and for measuring relative efficiency.

[63] The rationale for using the indicative approach outlined is as follows. First, the approach is used in Jha, A.K. (2005), 'Institutions, Performance, and the Financing of Infrastructure Services in the Caribbean', World Bank Working Paper no. 58, Second, OPEX data may not be strictly comparable across the CARILEC dataset owing to variations across entities in accounting practices, whereas employee numbers are more likely to be consistent (although Oxera has also encountered an issue of comparability of the FTE numbers—see below). Third, Fortis TCI uses the reciprocal of the unit cost indicators as a key performance indicator in its internal processes (ie, productivity indicators—customers per employee, MWh per employee). Fourth, the cost function fitted in the charts takes account of economies of scale (which are not captured in ranking simple unit FTE:customer measures), and so does not unduly penalise smaller companies (as regards their efficiency) compared with unit measures. Fifth, the natural logarithm approach also recognises 'curvature' in economies of scale—that is, as scale increases, the marginal impact on savings in FTEs (in absolute terms) falls. The function is therefore more conducive to including and comparing observations at the extremities of scale (small and large entities). It is more forgiving towards smaller companies than a straight-line approach.

[64] Fortis TCI participated in the CARILEC survey for the first time in 2009, but regards the data it submitted on FTE numbers for this exercise as inconsistent with the data submitted by other companies, due to a misunderstanding of how FTE numbers should be measured. As such, the above charts replace information for Fortis TCI submitted in the CARILEC study on FTE employees ([✂] FTEs) with data from the Fortis TCI's audited financial statements, covering both PPC and AEP, for 2009 (of [

An inefficient business could be expected to do more to improve its efficiency going forward, in order to catch up to best practice. In addition to this ‘catch-up’ in efficiency, best practice (or the ‘efficiency frontier’) could be expected to improve over time. Oxera has not analysed the scope for Fortis TCI and TCU to achieve future ‘catch-up’ efficiencies or the scope for frontier efficiency improvements. For example, if demand increases in the medium term, this could naturally lead to reduced unit operating costs for both TCU and Fortis TCI (given that some of their labour and other operating costs are fixed in nature).

What the above analyses would appear to suggest is that TCU appears to be slightly more efficient than average, and Fortis TCI slightly less so, on FTE employees to customers; while TCU is of average efficiency, and Fortis TCI is more efficient than average, on FTE employees to GWh. Furthermore, both companies appear to have further scope to increase efficiency, especially on number of FTEs to customers, in order to attain best practice. It is important to stress that to establish definitively the comparative efficiency of these companies would probably require more extensive analysis than undertaken as part of this report.

3.3 Fortis TCI and TCU cost structures

In examining the risks to which Fortis TCI and TCU are exposed under the current regulatory regime and in designing an appropriate regulatory framework, it is important to consider the allocation of risk. That is, how much of what types of risk should be placed with the regulated business and its investors, and what risks should be borne by other stakeholders, notably customers. The answer will depend on the nature and magnitude of risks to revenues and costs, and the ability of the management of the regulated business to control the drivers of risk, mitigate its exposure to risk, or otherwise bear the risk. For example, for costs that lie more within the control of the business, and which are also more predictable or less volatile over time, it may be more economical for the company to bear these risks. Indeed, it may be sensible to incentivise companies to increase efficiency in terms of, say, OPEX or CAPEX, recognising that the strength of such incentives to reduce costs needs to be balanced against the possibility that output, quality of service, and/or investment may be impaired.[65]

3.3.1 Operating costs

To obtain a better understanding of the nature of costs on TCI, for illustration Oxera asked Fortis TCI and TCU for a breakdown of their cost structures split by generation, distribution, retail (customer services), and other costs. This was to identify, at each stage, the key components of the costs, and their magnitude, drivers and variability.

Fortis TCI

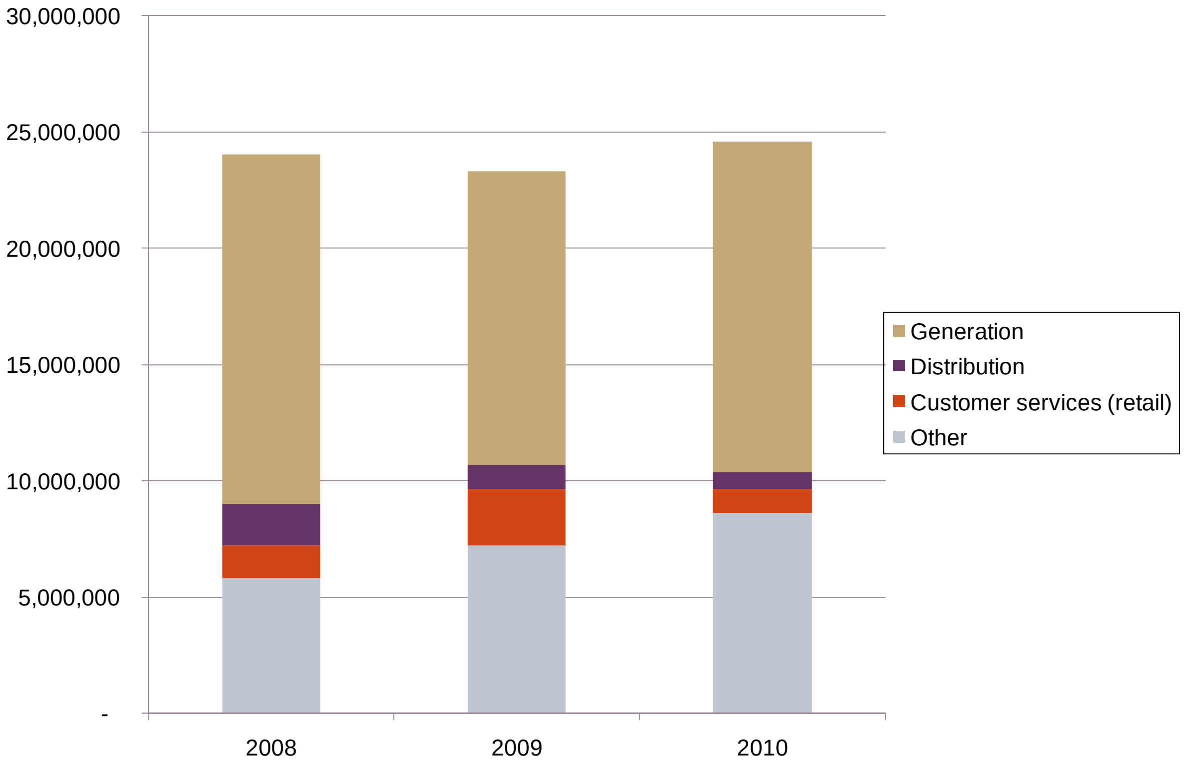
Figure 3.10 provides a high-level breakdown of OPEX for Fortis TCI (PPC area) over the period 2008–10. This includes maintenance expenditure. As can be observed, generation costs form the largest single component of day-to-day running costs, representing 58% of OPEX in 2010. Costs in the ‘other’ category (administration and overheads) are the next largest single component, representing 35% of OPEX in 2010. Distribution and retail (customer) services account for lower proportions of total OPEX. However, only direct wages OPEX is allocated to these services; moreover, the overheads activities benefit the business as a whole.

✂]). The FTE numbers in the financial statements are significantly lower than those presented in the CARILEC study. For consistency, the TCU numbers presented in the charts have also been taken from the company’s audited financial statements for 2009. In this instance, the audited financial statement numbers ([✂]) are slightly lower than those presented in the CARILEC study ([✂]).

[65] In practice, the regulator is typically less able than the company itself to assess the actual impact of potential risk factors on the business, or the anticipated scale of future efficiency improvements. This is to be expected, given that the management of a company has better information on its own potential performance improvements. Regulators often therefore use regulatory incentives that help to reveal the efficient level of cost (see section 6).

Administration and overheads costs increased in the period to 2010, while distribution and customer services OPEX fell in 2010. Movements in some cost categories (eg, distribution) reflect changes in accounting policies over time.

Figure 3.10 Breakdown of OPEX for Fortis TCI, 2008–10 (PPC area) ($)



Note: Depreciation and interest payments are excluded from the analysis, although maintenance is included. 'Other' refers to administration and overheads. Figures are in 'as current year' (nominal) prices.
Source: Based on Fortis TCI analysis.

In addition to the breakdown of operating costs shown above, Fortis TCI provided an indication of the main cost drivers, and the degree of cost controllability and variability.

– As seen in Figure 3.10, generation represents the largest single component of OPEX (58%), and by far the greatest component of generation costs are fuel purchase costs. Fuel costs rose by around 11% in this three-year period, and Fortis TCI regards these costs as uncontrollable and volatile.

– In comparison, wage costs for generation, distribution and retail activities constitute a significant proportion of OPEX (10%), although this includes only direct wage costs (administration and overhead costs are excluded, which also have a high share in total labour costs). Direct wage costs have increased in each of the three years of the period. Fortis TCI regards direct wage costs as uncontrollable and market-determined, except with regard to the addition of new staff resources.

  It is reasonable to assume that wage rates are partly beyond the control of an individual firm, although a company would be expected to have control over some aspects of its total wage bill—for example, by periodically reviewing the structure of its remuneration packages, staffing decisions, and management practices that influence staff utilisation.

– Maintenance costs for generation equipment and for distribution infrastructure also constitute a relatively small proportion of total OPEX (6%). Fortis TCI has discretion on when to undertake planned maintenance, and it recognises that these costs are partly under management control.

– Costs allocated to retail activities also include bad debts, which represent electricity bills issued to customers that have not been paid and are ultimately written off. In 2010 bad debts were negative, since arrears previously written off by Fortis TCI were recovered. Fortis TCI regards bad debts as non-controllable, since non-payment is expected to be driven in part by the cost of wholesale diesel fuel (which has been rising) and the state of the wider economy. While this could be reasonable, it is also likely that improved information provision could help customers to better plan and budget their household expenditure, and thus mitigate the extent of bad debt.

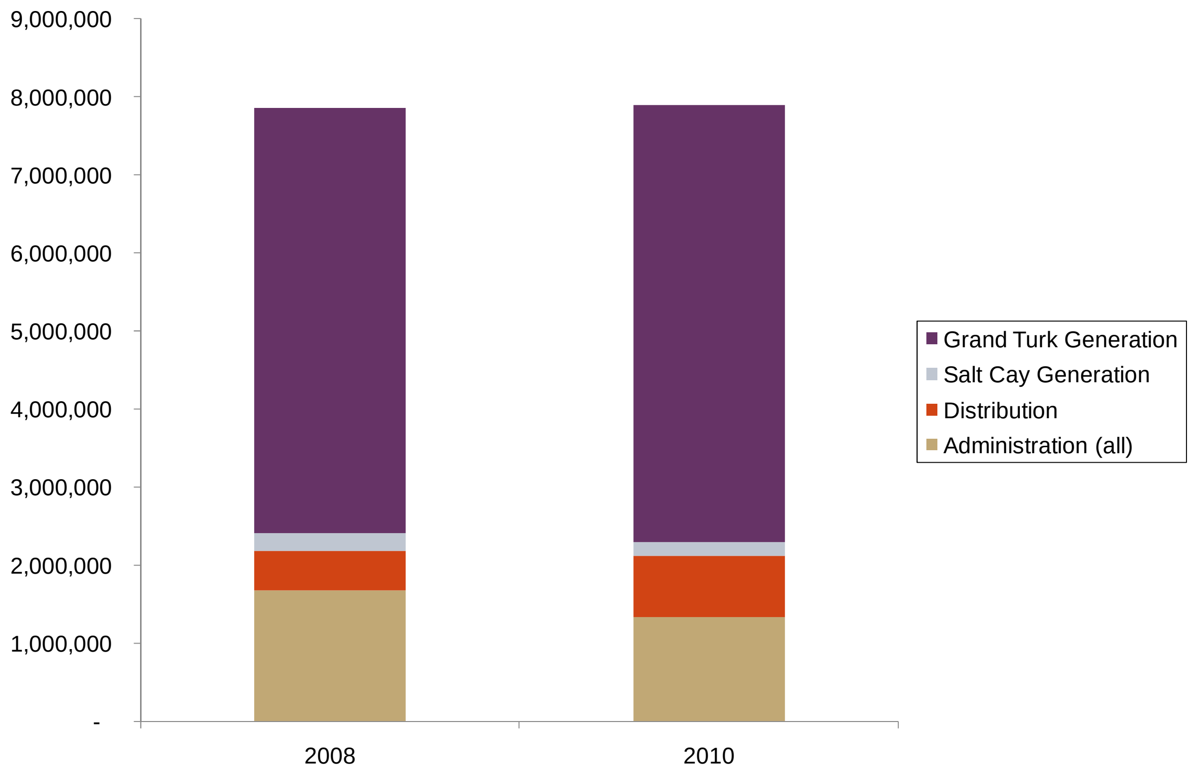
– Although not shown in Figure 3.10, administration and overhead costs were a key component of total OPEX in 2010 (35%). These are 'unallocated' costs that serve the needs of the entire business. As discussed in section 3.2, there tend to be economies of scale in these costs, since, at any given scale of operations, they are largely fixed.

  In the case of Fortis TCI, administration and overhead costs have increased in the three-year period by around 48%, partly due to accounting reallocations from other cost centres. However, other elements of overheads have also risen, such as transport, corporate services, IT, materials management, and human resources. Fortis TCI regards some of these overhead and administration costs as 'uncontrollable', some as 'partly controllable', and some as 'mostly controllable'.

TCU

Figure 3.11 gives an overview of TCU's operating costs. The breakdown is not strictly comparable to Fortis TCI's costs.[66]

Figure 3.11 Breakdown of OPEX for TCU ($)



Note: Interest and depreciation are excluded in the figure. Figures are in 'as current year' (nominal) prices.
Source: Schedule 4 of TCU annual regulatory submission for 2008 and 2010.

However, what can be observed is that:

[66] For example, in the case of the TCU, customer services and administration are grouped together.

– generation represents the highest proportion of total OPEX, and a higher proportion than for Fortis TCI (in 2010 Grand Turk plus Salt Cay generation costs were 73% of total OPEX);
– TCU distribution OPEX (including maintenance costs) grew over the period 2008–2010 (by 57%);
– in 2010 administration costs accounted for a lower proportion of total costs for TCU than for Fortis TCI.

Although some of these differences relate to the size and operating environments of the two companies (in particular, the larger share of generation costs faced by TCU), some may also be partly explained by differences in cost allocation.[67]

Assessment

Figures 3.10 and 3.11 highlight that fuel costs are the single most uncontrollable and unpredictable cost faced by Fortis TCI and TCU. The level of risk implied by this cost driver would support the retention of a mechanism such as the fuel cost adjustment to enable this cost to be passed through to customers.

Other areas of cost are either partly controllable, or, even if they are less controllable, would appear to be much less significant than fuel costs in terms of cost risk. While some categories of non-fuel costs may increase, this may be offset by reductions elsewhere. The implication is that regulatory incentives could be applied to encourage greater operating efficiencies, particularly as the companies themselves are better placed than customers to influence these costs, and could reasonably be expected to bear these risks.

In the case of Fortis TCI, administration and overhead costs appear to be escalating and it is not clear whether these increases are all efficient. In so far as some costs are driven by inflation, it would be important to recognise that some allowance for increases in the general price level is necessary.

3.3.2 Capital costs

Over the past few years, both Fortis TCI and TCU have undertaken significant amounts of capital investment in upgrading and expanding their generation and distribution assets. This has improved the reliability of service for customers, but has also led to excess capacity.

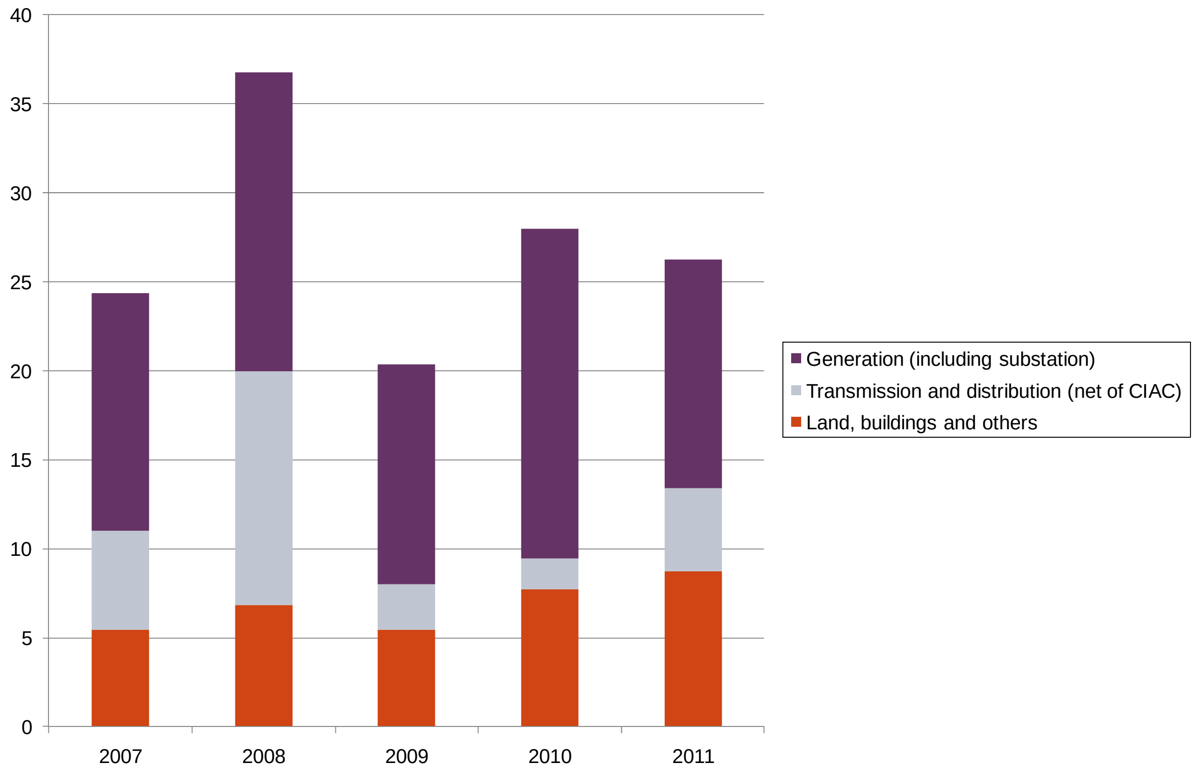
The increased investment was, in particular, driven by a year-on-year increase in peak demand from the early 2000s onwards. In Providenciales, this was driven by rapid growth in tourism, and hence in hotel and condominium development, with consequent growth in the commercial sector. Demand growth in Grand Turk was also driven by tourism.

In 2008, however, this demand growth slowed considerably in Providenciales, while demand actually fell in Grand Turk. The stalling of demand was due to the combined impacts of Hurricane Ike (which destroyed the vast majority of TCU's distribution network), and the impact on tourism and development of the global economic slowdown.[68]

Following its takeover of PPC and AEP, Fortis TCI began a five-year capital expansion programme (see Figure 3.12 for a breakdown of this), which was driven by 'asset modernisation, improved reliability and efficiency'.[69]. The programme included investment in new generation facilities to cope with increased demand. Figure 3.12 illustrates how overall capital investment peaked in 2008 and contracted significantly in 2009.

[67] Also, for TCU, some costs classed as administration in 2008 may have been allocated to generation and distribution 'other' in 2010, as this category did not exist in 2008.
[68] See Castalia (2011), op. cit., pp. 12 and 23.
[69] PPC annual regulatory filing (2010).

Figure 3.12 Fortis TCI (PPC area) historical CAPEX by value chain activity ($m)



Note: Figures are in ‘as current year’ (nominal) prices. 2011 is a forecast. CIAC refers to contributions in aid of construction.
Source: PPC presentation February 7th; PPC Regulatory filing December 2010.

Before its takeover in 2006, PPC used a mixture of Caterpillar high-speed ‘containerised’ units, mounted on trailers, and housed medium-speed Caterpillar units. After 2006, Fortis TCI commissioned additional and more modern medium-speed (and housed) Caterpillar units, of higher capacity, some of which came from the second-hand market. The effect of these investments was to begin to place the older—and less fuel-efficient—trailer units on standby.[70] Fortis TCI also invested in improving the reliability of the distribution network.

The 2008 hurricane led to an urgent need to replace damaged parts of the overhead distribution network. However, the economic crisis, and the consequent slowdown in demand, led to lower overall investment in 2009. Annual peak demand growth in 2006 was 22%, but by 2009 this had slowed to less than 5%.[71]

2010, which marked year four of the capital expansion programme, saw the construction of a new on-site diesel storage facility, increasing fuel storage from three to ten days.

The company also commissioned the first of two Wartsilla generating units, sourced from Finland.[72] A business case for the units was prepared in 2009.[73] The intention was to save on maintenance costs (for example, the units are completely sealed and are less vulnerable to dust intrusion than the older Caterpillar units), and to improve on fuel-burn efficiency (the units are higher-capacity than the existing medium-speed Caterpillar units), rather than to accommodate additional demand.[74] The business has highlighted that it negotiated a fixed-

[70] See Castalia (2011), op. cit.
[71] See Castalia (2011), op. cit., March 31st, p. 12, which was itself based on meetings with PPC management.
[72] PPC annual regulatory filing (2010).
[73] PPC (2009), ‘Project business case. G13 development options’, Version 1.0, Confidential, March.
[74] PPC annual regulatory filing (2010); discussions with management during Oxera site visit 2011; Castalia (2011), op. cit.

price servicing contract to cover ongoing maintenance of the units.[75] Commissioning the Wartsilla units means that the high-speed trailer units can eventually be phased out.[76]

Nonetheless, the combination of a decline in demand in 2008 and the recent investments in generation has led to a high reserve capacity margin.[77] This will increase further with the commissioning of the second Wartsilla engine.

In 2010 construction also began on a new corporate and customer care headquarters. This replaced several (previously separate) sites, and was constructed during a period in which construction costs were lower due to the economic slowdown.[78] There was also investment in new IT infrastructure.[79] CAPEX represented 25% of total company costs in 2010.[80] The fuel storage unit was brought on line in early 2011, and the new headquarters in mid-2011. The second Wartsilla unit was also brought on line in August 2011.[81] The business aimed to move facilities that were outside into an indoor mechanical workshop, and to complete a new substation. From the site visit, it emerged that the company had significantly improved the assets, safety, and the working environment of its staff.

After 2012 the company expects CAPEX to ‘decrease significantly’, with future CAPEX driven predominantly by any future demand growth. In the longer term, the company plans to increase interconnection, in particular by extending the main network to East Caicos and South Caicos.[82]

Figure 3.13 gives an overview of the TCU’s capital projects over the past few years. As a smaller entity than Fortis TCI, TCU uses low-capacity high-speed Caterpillar units, a number of which are containerised. Six of the units are located in one plant on Grand Turk. Two (smaller units) are used to serve the separate Salt Cay system.[83] Some years ago, Salt Cay had been served through an interconnector from Grand Turk, but this was highly vulnerable to corrosion and breakage.[84]

[75] Based on discussions with management during Oxera site visit 2011.

[76] PPC annual regulatory filing (2010).

[77] Based on Castalia (2011), op. cit.; and Oxera discussions with the company.

[78] Based on discussions with the company during the site visit.

[79] Based on PPC annual regulatory filing (2010); and Oxera site visit.

[80] PPC (2011), ‘Energy as a factor in sustainable development and its impact on the cost of doing business in the TCI’, presentation held on February 7th.

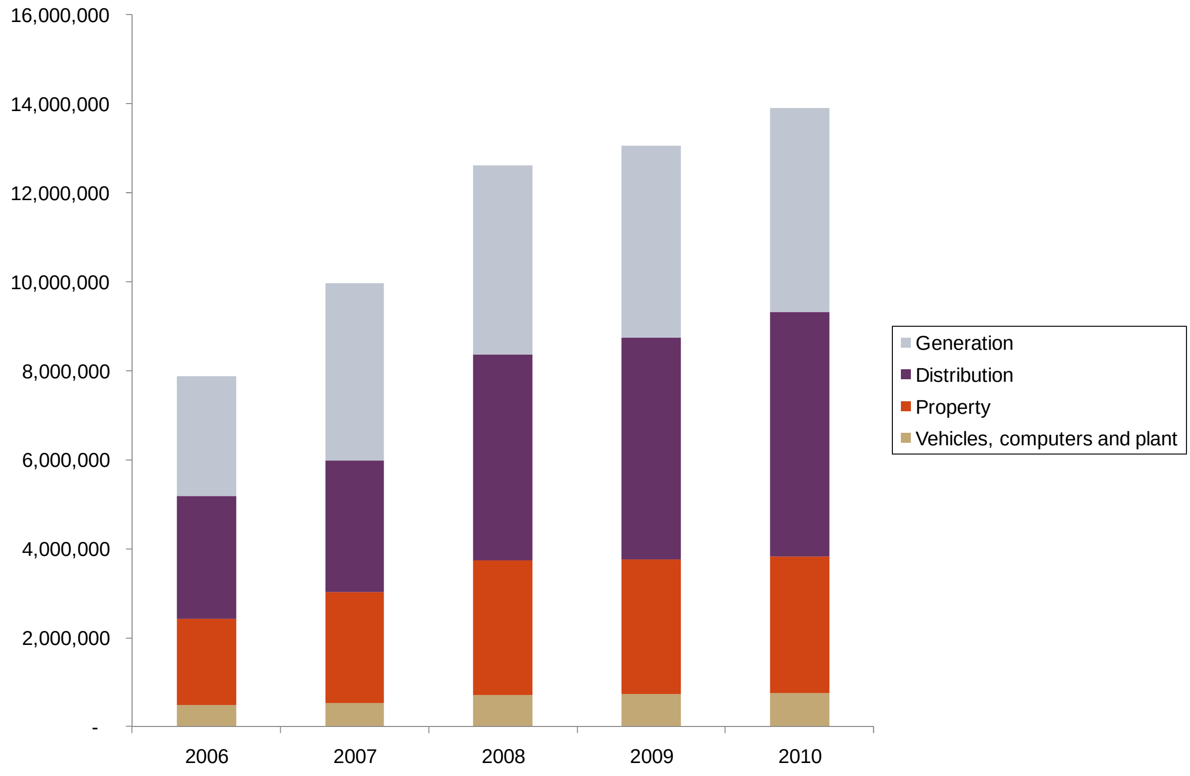
[81] Fortis TCI (2011), ‘Fortis TCI’s Second Wartsilla Engine Ready for Operation’, press release, August 8th.

[82] PPC annual regulatory filing (2010); PPC (2011), ‘Energy as a factor in sustainable development and its impact on the cost of doing business in the TCI’, presentation held on February 7th.

[83] See Castalia (2011), op. cit.

[84] Based on Oxera discussions with the company in 2011.

Figure 3.13 TCU historical CAPEX by value chain activity ($)



Note: Totals for each activity are net of asset disposals. Figures are in 'as current year' (nominal) prices. Source: Schedule 7 of the audited financial statements 2008 to 2010 (asset additions and disposals of property, plant and equipment).

Prior to 2008, TCU (like PPC) experienced a significant increase in peak demand. Two of the existing Grand Turk units were installed in 2006–07, to deal with peak loads and prevent overloading in the face of this rising demand.

TCU was also in the process of seeking to expand its generation capacity further when, in 2008, Hurricane Ike destroyed 95% of its distribution system, and it turned its attention to replacing this.[85]

While TCU had identified that additional generation capacity might be required in late 2012, this plan was revised in 2009 following the global economic slowdown. It was subsequently identified that no additional units would be required before 2014; instead TCU brought on line a third feeder in 2010, reconfiguring the distribution network to increase resilience.

In early 2011, TCU sold one of its generating units, since it regarded its reserve capacity margins as 'high'. However, a fire subsequently destroyed one of the neighbouring units, requiring TCU to rent some trailer units on a temporary basis. It plans to replace these with company-owned units in late 2011.[86]

The drop in demand in 2008, following Hurricane Ike and the global economic downturn, led to an extensive reserve capacity margin. Nonetheless, the difficulties faced by TCU following the sale of one of its generating plant, and the subsequent fire, show how, for a very small electricity company, it can be difficult to lower reserve capacity margins without increasing risk. In its favour, however, the company benefits from its investment some years previously in bulk-fuel storage capacity, which provides two months of storage capacity (for example, to

[85] TCU (2011), TCU's system development plan 2011 to 2015, and discussions with TCU.

[86] Ibid.

deal with extreme weather events).[87] This is much greater than the ten days of storage available to Fortis TCI.

Based on analysis in July 2011, and in the current economic climate, TCU does not see any need to add generating capacity, or change major distribution equipment, until after 2015.[88] Its future CAPEX is therefore likely to be somewhat less going forward than that incurred to date.

In 2009 the company put forward proposals, for the longer term, to install hybrid wind/solar generation on Grand Turk. In 2010, the government granted TCU the right to undertake wind studies over a three-year period, using Crown land. However, the company has encountered difficulties in securing a long-term licence and the land necessary to install and operate a wind farm.[89] More recently, there have been further delays due to the need to install meteorological towers on Crown land, to conduct the necessary wind tests. Lack of availability of land is seen as a key barrier by TCU to developing wind generation at utility scale on Grand Turk in the future.[90]

3.4 Business planning and benchmarking initiatives

Both TCU and Fortis TCI participate in the annual CARILEC benchmarking survey. Fortis TCI is a more recent participant, having joined in 2009. They also both undertake investment planning and consider different options to address future needs. Fortis TCI provided examples of past and planned initiatives as part of its overall business planning and in terms of keeping track of performance, which include the following.

– Details of its overall capital budgeting and planning approach, as well as specific business cases for CAPEX areas (such as investment in the new Wartsilla plant).

– An annual (draft) business plan which, in addition to strategy, includes company targets for various KPIs.

– A corporate scorecard, which Fortis TCI monitors to keep track of performance over time across various operational and financial metrics of importance to the core business.

– Details of a KPI benchmarking project that the company was setting up in 2011.

– Presentations to the TCI Government on how Fortis TCI had performed on various system performance and reliability indicators.

– Details of a customer service questionnaire from 2009, on self-reported satisfaction.

These initiatives illustrate that Fortis TCI already prepares, or is in the process of preparing, information and initiatives on its CAPEX, OPEX and service performance. While a number of the monitored measures reflect internal corporate targets, such information may also be useful for regulatory purposes as part of a reformed system of regulation. As TCU is significantly smaller than Fortis TCI, any future information requirements should bear this in mind.

[87] TCU (2011), TCU's system development plan 2011 to 2015, and discussions with TCU.
[88] Ibid.
[89] Ibid. TCU's solar/wind hybrid renewable plans were put forward in TCU (2009), 'Renewable Energy Development Strategy. Turks and Caicos Utilities, Ltd. (Business Confidential)'.
[90] Based on Castalia (2011), op. cit., and discussions with TCU.

3.5 Summary

The residential tariffs charged by TCU and Fortis TCI are among the highest in the Caribbean. However, larger jurisdictions appear generally to have lower tariffs than smaller ones, as evidenced by the correlation between the size of the customer base and residential tariffs, indicating that there are economies of scale in electricity provision.

Indeed, Caribbean jurisdictions suffer from a common problem of lack of scale, lack of interconnection, dependence on expensive diesel fuel, a need for high capacity margins, and exposure to severe weather events. However, since TCI is among the smaller—and more remote—jurisdictions in the Caribbean, this limits the potential for a more diverse mix of fossil fuels to be used on the islands (fuel is imported via the Bahamas and there is a lack of deep-water ports). Owing to its remoteness compared with the collection of Eastern Caribbean islands, electrical interconnection possibilities between TCI and other jurisdictions are limited.

Taken together, these factors imply that the costs of electricity on TCI (and tariffs) are high due to the inherent circumstances on TCI, which gives rise to high dependence on diesel, high capacity reserve margins, and high fuel purchasing costs. This also gives rise to lower labour productivity (if only measured as a ratio of employees per customer) than in many larger jurisdictions.

Having said this, TCU's capacity margins are very high (although this has a particularly small operating area). Moreover, while Fortis TCI's capacity margins in 2009 were comparable at the time to those of other similar jurisdictions, these have increased significantly in recent months. It is unclear that these capacity margins are necessarily efficient.

An indicative analysis of labour productivity presents mixed evidence on the operating efficiency of the companies. Taking account of their size (and employing significant adjustments to the employee figures submitted by Fortis TCI to CARILEC), on labour productivity the companies appear to be 'about average' for the Caribbean. This indicates, however, that they both have scope to improve.

Both companies have invested significantly in their assets over recent years. Much of the investment undertaken was a legacy of peak demand growth prior to 2008, which has since abated. Since 2008, TCU switched priorities to investing heavily in network restoration, following the impact of Hurricane Ike, which might be regarded as investment that it had little choice but to undertake. Fortis TCI has, since 2008, continued to invest, in new Wartsilla generating units, IT systems and a new corporate headquarters. This has led to improvements in the assets, safety, and the working environment of staff. However, the current regulatory regime does not provide powers to approve or examine these more 'discretionary' investments. Indeed, the investments made by both companies have led to highly reliable systems, but significant investment has been undertaken, and the extent to which this has necessarily been efficient is unclear.

An analysis of the operating costs of the companies shows that generation (and fuel costs in particular) are significant elements of costs, which are also largely beyond the control of the companies (see also section 2). The level of risk implied by this cost driver would support the retention of a mechanism such as the fuel cost adjustment to enable this cost to be passed through to customers. Other areas of cost are either partly controllable, or much less significant than fuel costs in terms of cost risk. While some categories of non-fuel costs may increase, this may be offset by reductions elsewhere. This implies that regulatory incentives could be applied to encourage greater operating efficiencies. In the case of Fortis TCI, administration and overhead costs appear to be escalating and it is not clear whether these increases are efficient (although some of the cost increases will be driven by inflation).

4 Financial performance

This section presents evidence on the financial performance of Fortis TCI and TCU by analysing their historical profitability and benchmarking their historical returns against estimates of their cost of capital. The section also reviews a range of methods for assessing profitability that are relevant in this context.

Appendix 1 provides further information on the assumptions underpinning the analysis presented in this section, focusing on the principles of profitability assessment and the cost of capital calculations.

The relevance of this profitability analysis to the regulatory review and the design of an appropriate regulatory framework relates to whether Fortis TCI and TCU's profitability levels are 'reasonable'. For example, to the extent that a firm is able to earn profits that are not reflective of its underlying risks, it would be reasonable for the regulator to reduce tariffs to a level commensurate with the returns expected by the firm's investors. Conversely, if profits are likely to be below the returns required by investors, tariffs may need to rise to ensure that a company can raise the capital necessary to enable further investment, all else being equal.

4.1 Profitability indicators and estimation

4.1.1 Practical considerations

In the context of this report, the profitability assessment consists of an ex post analysis of the level of actual returns earned by TCI electricity companies using a suitable indicator or indicators. These returns are then compared with the level of return that would be required to compensate the companies' providers of finance (debt or equity finance) for the risk of investing in those companies (ie, the companies' cost of capital). If the actual returns were to exceed the cost of capital (the competitive benchmark for the level of profitability), this would indicate that tariffs might be excessive and that the regulatory regime has allowed companies to exercise some market power. Conversely, if actual returns were to be consistently below the cost of capital, this might indicate that the main shortcoming of the regulatory regime is that it does not allow electricity companies to be normally profitable in line with a competitive benchmark.

In a competitive market, profitability is likely to vary across time, and individual companies may be above or below the benchmark in any given year. The theory would indicate that, in the presence of persistently high profits, new firms would enter the market until the firms in the market achieve a 'normal' or benchmark level. In practice, a company's returns can vary year on year for a number of reasons (eg, phase of the business cycle, specific factors such as weather or natural disasters that are not under management control, etc). In this context assessing whether the level of returns earned by a company are above the cost of capital in only one given year is unlikely to provide useful information on whether the measured level is excessive.

However, over a medium to long term, it would be reasonable to expect that returns of TCI electricity companies will be consistent with their cost of capital. Oxera's analysis focuses on a period of ten years (2001 to 2010) in order to consider the level of returns over time.

It is important to stress that the results reported in this section and in Appendix 1 are indicative of past performance and provide the order of magnitude of the returns that investors would have expected in order to invest in TCI electricity companies. This is different from calculating the cost of capital to be used in regulatory decisions going forward, which would require a more extensive analysis of backward- and forward-looking evidence on each parameter used in the calculation. This simplified analysis is suitable, however, to provide an overall indication on how TCI electricity companies have performed over the past ten years.

4.1.2 Overview of profitability indicators

Regulators, competition authorities and financial analysts have tended to use a number of proxy indicators for economic profitability. Economic and financial theory indicate that the conceptually correct measures of profitability of an investment, a business line or a business as a whole are the internal rate of return (IRR) and the net present value (NPV).[91] These measures are ideally calculated over the life of the relevant investment.[92]

It is possible to calculate the IRR over a time period shorter than the life of the asset (this is known as the 'truncated IRR'). To do this, it is necessary to have knowledge of the cash flows at the level of the investment, segment or business being evaluated during the relevant period, as well as the value of the assets at the beginning and end of the period according to the 'value-to-the-owner' principle. Consistent with this principle, modern equivalent asset (MEA) valuation of assets provides the correct asset values at the start and end of the measurement period, and it is these that are then compared against the competitive benchmark.[93]

Profitability measures using company accounts, such as return on capital employed (ROCE) or return on equity (ROE), are not the same as the IRR, but do have some systematic links to it.[94] It has been shown that the assessment of economic profitability using ROCE would produce values close to the IRR method where MEA valuation is used as the basis of asset valuation, all changes in book value of assets flow through the profit and loss account, and yearly results are correctly weighted to elicit an overall return estimate.[95] However, at no point during the period considered has Fortis TCI or TCU estimated the value of its assets using MEA valuations. A simplifying assumption is therefore to use book values as a proxy for the correct asset value to use in the profitability analysis on the basis of ROCE (the measure often used by regulators).

4.1.3 Estimation of ROCE

ROCE is defined as the ratio between the earnings before interest and taxes (EBIT) and the capital employed. Tables 4.1 and 4.2 present details of the turnover and EBIT of Fortis TCI and TCU over the period 2001–10 respectively.

[91] See, for example, Brealey, R. A., Myers, S.C. and Allen, F. (2010), *Principles of Corporate Finance*, tenth edition, McGraw Hill/Irwin; and Edwards, J., Kay, J.A. and Mayer, C. (1987), *The Economic Analysis of Accounting Profitability*, Oxford University Press.

[92] Other indicators are discussed in the Appendix.

[93] See, for example, Mayer, C. (1988), 'The real value of companies accounts', *Fiscal Studies*, **9**, 1–17.

[94] See Edwards et al. (1986) op. cit. See also Franks and Hodges (1996), 'The meaning of accounting numbers target setting and performance measurement: implications for managers and regulators', in R.P. Peasnell and K.V. Brief (eds), *Clean up surplus: a link between accounting and finance*, Garland Publishing.

[95] See, for example, OFT (2003), 'Assessing profitability in competition policy analysis', Economic Discussion Paper 6, p. 54.

Table 4.1 Turnover and EBIT for Fortis TCI, 2001–10 ($’000)

Year	Turnover	EBIT
2001	[✂]	[✂]
2002	[✂]	[✂]
2003	[✂]	[✂]
2004	[✂]	[✂]
2005	[✂]	[✂]
2006	[✂]	[✂]
2007	[✂]	[✂]
2008	[✂]	[✂]
2009	[✂]	[✂]
2010	[✂]	[✂]

Note: The table contains consolidated data for Fortis TCI (PPC) and AEP.
Source: Oxera analysis and annual audited financial statements provided by Fortis TCI (PPC) and AEP.

Table 4.2 Turnover and EBIT for TCU, 2001–10 ($’000)

Year	Turnover	EBIT
2001	[✂]	[✂]
2002	[✂]	[✂]
2003	[✂]	[✂]
2004	[✂]	[✂]
2005	[✂]	[✂]
2006	[✂]	[✂]
2007	[✂]	[✂]
2008	[✂]	[✂]
2009	[✂]	[✂]
2010	[✂]	[✂]

Source: Oxera analysis and annual audited financial statements provided by TCU.

The use of book value to assess the asset value is important here. According to international financial standards, the book value would report the historical cost of acquisition asset values. At privatisation in 1986, PPC, TCU and AEP were transferred at a nominal amount ($1). The book value was calculated on the basis of an engineering estimate for PPC, and $900,000 for TCU. Subsequent additions were included in the book value at cost (replacement of components of an asset are added to an asset carrying amount). The asset base as reported in the financial statements is therefore at historical costs, with an initial value at privatisation as the starting point.

The alternative approach would be to use replacement cost values. However, both companies have had to replace a large part of their networks since Hurricane Ike in 2008. In addition, Fortis TCI has been undertaking a large investment plan since its takeover of PPC and AEP in 2006 (eg, replacement and expansion of generation capacity).

As a result, the accounting estimates of the capital employed (ie, ‘book value’) for 2008 onwards are arguably unlikely to differ substantially from a replacement cost valuation of the asset base. It is somewhat more difficult to assess whether the replacement has been carried out such that these estimates represent a good proxy of an MEA value estimate of the network. For example, a like-for-like replacement of assets would be restricted by the legacy network configuration, generation capacity and technologies. These might not result in the least-cost configuration and choice of feasible technologies and capacity going forward that would be assumed in the context of an MEA valuation.

In so far as the years before 2008 are concerned, if asset values were expressed at replacement value, depreciated to take into account the proportion of the asset that has already been used, the holding gain from revaluing the assets should be posted to the profit and loss account. Therefore, while capital employed would be higher with a depreciated replacement cost asset value, so would profits (including holding gains).

On balance, examining returns based on the historical cost of acquisition still appears to be a useful basis to examine historical levels of profitability.

Capital employed is normally calculated as total assets net of current liabilities. A breakdown of total fixed assets, current assets and current liabilities for Fortis TCI and TCU over the period 2001–10 is presented in Tables 4.3 and 4.4.

Table 4.3 Fortis TCI: total fixed assets, current assets and current liabilities, 2001–10 ($'000)

Year	Total fixed assets	Current assets	Current liabilities
2001	[✂]	[✂]	[✂]
2002	[✂]	[✂]	[✂]
2003	[✂]	[✂]	[✂]
2004	[✂]	[✂]	[✂]
2005	[✂]	[✂]	[✂]
2006	[✂]	[✂]	[✂]
2007	[✂]	[✂]	[✂]
2008	[✂]	[✂]	[✂]
2009	[✂]	[✂]	[✂]
2010	[✂]	[✂]	[✂]

Note: The figures for Fortis TCI are an aggregate of values for Fortis TCI (PPC) and AEP, and include only items (in each category) from the balance sheet that have entered the ROCE calculations.
Source: Annual audited financial statements provided by Fortis TCI (PPC) and AEP.

Table 4.4 TCU: total fixed assets, current assets and current liabilities, 2001–10 ($'000)

Year	Total fixed assets	Current assets	Current liabilities
2001	[✂]	[✂]	[✂]
2002	[✂]	[✂]	[✂]
2003	[✂]	[✂]	[✂]
2004	[✂]	[✂]	[✂]
2005	[✂]	[✂]	[✂]
2006	[✂]	[✂]	[✂]
2007	[✂]	[✂]	[✂]
2008	[✂]	[✂]	[✂]
2009	[✂]	[✂]	[✂]
2010	[✂]	[✂]	[✂]

Note: The figures include only items (in each category) from the balance sheet that have entered the ROCE calculations.
Source: Annual audited financial statements provided by TCU.

Some aspects of the analysis need closer consideration:

– the traditional definition of capital employed (total assets less current liabilities) may exclude items of financing capital (eg, short-term borrowings for financing rather than operational purposes); where such items exist, they should be added back in order to derive capital employed;

– the depreciation rules may also affect the results and their consistency over time. For example, a change in depreciation rules such as asset life might shorten or lengthen the asset life, and thereby increase or reduce the depreciation charge and in turn the EBIT estimates.

The examination of the two issues above indicates that there is a case for considering part of TCU current liabilities as being destined to financing rather than used for operational purposes. This seems to be the case for liabilities reported in the financial statements as 'notes payable-current portion' 'due to related parties', and 'customers' deposits'. Therefore, for TCU, the capital employed was estimated as total assets net of current liabilities and then adding back notes payable-current portion, due to related parties and customers' deposit, resulting in total assets less the only other current liability, namely 'accounts payable and accrued expenses'.

For Fortis TCI (PPC), current liabilities comprise 'bank overdraft', 'current portion of long-term debt', 'contribution in aid of construction' and 'accounts payable and accrued expenses'. The examination of the current liabilities would suggest that there is a case to consider the first three items to be used for financing rather than operational purposes and not to be excluded from the capital employed. Also, current and non-current assets include 'due from fellow subsidiaries' throughout the period of analysis, which needs to be excluded from capital employed to the extent that they represent financing arrangements with the rest of the group. As such, capital employed is calculated as total assets net of 'accounts payable and accrued expenses' and 'due from fellow subsidiaries'. Contributions from customers are included in the capital employed throughout the analysis on the assumption that, when the asset is constructed, these contributions are accounted in the income statement as income. If this were not the case, customers' contributions should be excluded from the capital employed in order to ensure that shareholders/debt holders are not compensated for assets that they have not funded.

For Fortis TCI (AEP), current liabilities comprise ‘bank overdraft’, ‘current portion of long-term debt’, ‘accounts payable and accrued expenses’ and ‘due to fellow subsidiaries’. The examination of the current liabilities would suggest that there is a case to consider ‘bank overdraft’, ‘current portion of long-term debt’ and ‘due to fellow subsidiaries’ to be used for financing rather than operational purposes and not to be excluded from the capital employed.

As such, capital employed is calculated as total assets net of ‘accounts payable and accrued expenses’.

In the case of Fortis TCI (PPC), the company changed the asset life assumptions in the 2009 financial reporting. In particular, it extended the asset life for some asset categories. This has two impacts on the ROCE calculations: it lowers the depreciation charge and thereby increases EBIT; and it reduce the pace of asset value reduction, thereby increasing the level of capital employed used in the calculation compared with the values that would be obtained using the pre-existing depreciation rules.

The overall impact of a change to depreciation policy and the extension of asset lives is unclear because the implications for EBIT and capital employed can offset each other in part or in total. No adjustments were made to the calculations to have a consistent approach to depreciation throughout the period.

Table 4.5 shows the average annual capital employed (average of the year-opening and year-end values).

Table 4.5 Capital employed-average value ($ ‘000)

Year	Fortis TCI	TCU
2001	27,244	5,307
2002	31,128	5,309
2003	33,748	5,282
2004	34,800	5,278
2005	41,189	5,110
2006	53,794	5,279
2007	71,428	6,546
2008	99,389	9,058
2009	122,051	11,009
2010	141,149	11,781

Source: Oxera analysis.

The use of the estimates in Tables 4.1 to 4.5 results in the ROCE levels reported in Table 4.6 below.

Table 4.6 Annual ROCE estimates (%)

Year	Fortis TCI	TCU
2001	17.9	12.2
2002	16.7	8.1
2003	17.4	8.6
2004	14.1	14.9
2005	16.9	15.5
2006	14.9	25.0
2007	12.2	19.3
2008	7.6	10.0
2009	7.5	7.8
2010	7.4	9.2

Note: The ROCE for Fortis TCI is calculated by using information on Fortis TCI (PPC) and AEP.
Source: Oxera analysis.

4.2 Benchmarking profitability against the cost of capital

The cost of capital assessment is based on the weighted average cost of capital/capital asset pricing model (WACC/CAPM) framework.

As illustrated in this section, the calculations under this framework allow for the assessment of a range of values that represent the order of magnitude of returns that investors might have expected to earn when investing in TCI electricity companies. This is different from calculating the cost of capital used to set the prices when many of the assumptions described below would require more extensive scrutiny of likely changes over the regulatory period under consideration. In particular, this would require a more extensive analysis and consideration of both backward- and forward-looking evidence for each component of the calculation.

The simplified approach described is, however, suitable for an historical assessment of the companies' financial performance against reasonable level of returns that investors would have expected from investing in them.

The key parameters are as follows:

– a **nominal risk-free rate** calculated using ten-year maturity US Treasury bonds. An interval estimate of 3.5–4.5% is assumed for the period;

– **asset and equity beta**—the asset beta is estimated starting from the mean value of equity betas elicited for a group of companies selected as suitable comparators for TCI electricity companies over the period 2001–10. Values are estimated for raw and adjusted betas. The asset beta is in the range of 0.3–0.4 over the period, corresponding to a range of 0.59 and 0.79 for the equity beta;

– the **equity risk premium (ERP)** is estimated as the long-term historical average (arithmetic mean) US market premium over bonds (eg, 1900–2004). Over the period of the analysis, this is broadly within a range of 6.0–6.5%;

– a **debt premium** is calculated as the premium for BBB corporate bonds over the ten-year maturity US treasury bonds. Over the period, an interval of 1.5–2.0% is obtained;

– **gearing** is calculated as net debt divided by net debt plus market value of equity for each comparator company averaged over the period 2001–10. Over the period this is on average 49%.

Results are reported in Table 4.7 using the lower and higher end of the interval estimates (where applicable).

Table 4.7 WACC, 2001–10

	Low	High
Cost of equity		
Gearing	49%	49%
Corporate tax rate	0%	0%
Equity beta	0.59	0.79
Risk-free rate nominal	3.5%	4.5%
ERP nominal	6.0%	6.5%
Nominal post-tax cost of equity	7.0%	9.6%
Cost of debt		
Risk-free rate nominal	3.5%	4.5%
Debt premium	1.5%	2.0%
Nominal pre-tax cost of debt	5.0%	6.5%
WACC		
Nominal (pre-tax) WACC	6.0%	8.1%

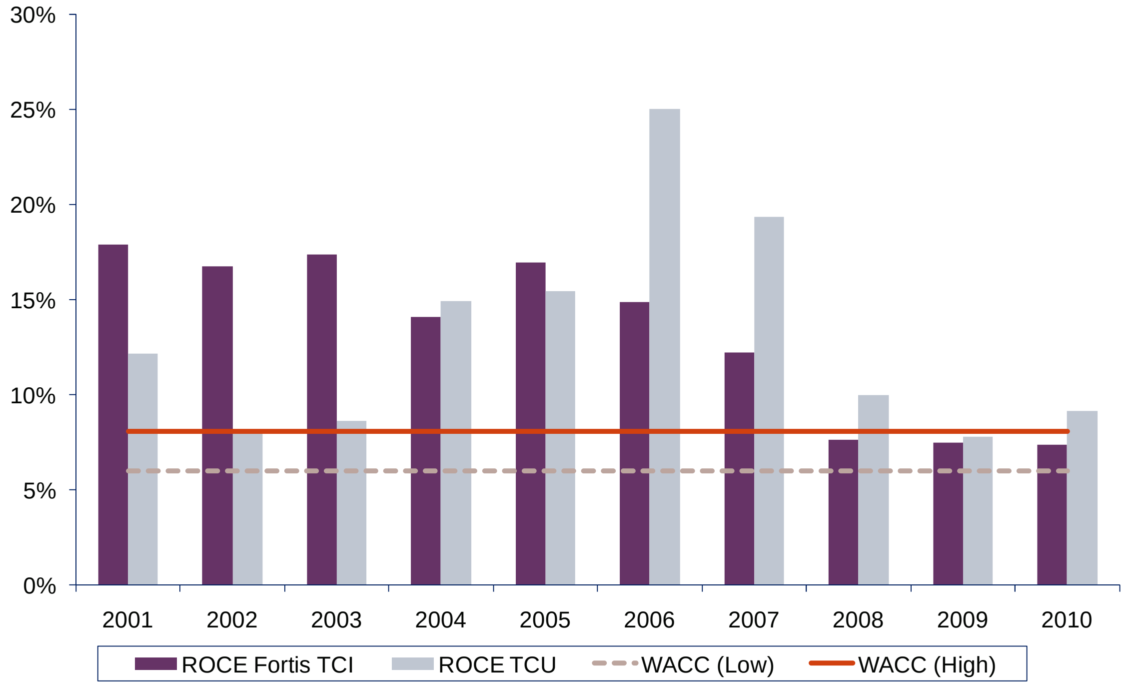
Source: Oxera analysis.

The analysis of the WACC assumes zero corporate tax, since this is the tax regime in TCI. However, the returns generated by companies in TCI may be subject to corporate tax once they are transferred to the parent companies. Investors would expect the level of returns to be increased such that they receive their expected returns once such corporate taxes are paid.

A more detailed analysis of the tax regime to which returns earned in TCI would need to examine more closely the type of ownership structure involved. Since the different origins of the owners are likely to result in different tax assumptions in the WACC, a simplifying assumption is to consider the tax regime where the operations take place, in this case TCI.

The cost of capital and ROCE for TCU and Fortis TCI are reported in Figure 4.1 below.

Figure 4.1 ROCE and WACC comparison



Source: Oxera analysis.

The cost of capital estimates are likely to be conservative since specific operational characteristics of TCI electricity companies (eg, small companies operating in tourism-dependent islands) expose them to higher risk than that facing the comparator companies used in the assessment of some parameters.

The greater risk related to a company's small size—and the related need to compensate investors for that greater risk—was recognised, for example, in a different regulatory context; namely, the water utilities in England and Wales. In its 2004 regulatory decision, the economic regulator, Ofwat, allowed for a cost of capital premium (up to 0.9%) for a very small company.[96]

Returns calculated for TCI electricity companies starting from 2008 seem to be broadly in line with what investors would have been likely to expect from these companies.

4.3 Summary

As noted, the results reported in this section and in Appendix 1 are indicative of past performance, and give the order of magnitude of the returns that investors would have expected in order to invest in TCI electricity companies.

The calculation of profitability using a ROCE analysis would indicate that both Fortis TCI (including PPC and AEP) and TCU earned high returns until 2008.

Returns since 2008 appear to be in line with the broad level of returns that investors would have reasonably expected from investing in TCI electricity companies. Due to the high level of CAPEX incurred to replace assets following hurricane Ike, the book value of assets can be argued to be a closer approximation of replacement cost in recent years; hence, it would follow that the ROCE estimates since 2008 provide a more accurate reflection of the economic profitability of the TCI energy companies compared with earlier years. Similarly, it

[96] Ofwat (2004), 'Future of water charges 2005-2010: final determinations', p. 226.

is possible that the return estimates in earlier years may have been biased upwards due to the lack of accurate information on replacement cost for those years.

However, the primary driver in lowering the level of return is the increase in the asset base, not the decrease in operating profit. ROCE is a measure sensitive to changes in the asset base, and it is therefore not surprising that there is some variability in the results.

It is also important to note that, to the extent that a utility undertakes excessive investments in capacity leading to idle plants or underutilised assets, it is possible that measured profitability may be at a ‘reasonable’ level at the same time as customers are charged excessively high tariffs. Therefore, going forward, it is important that the regulatory framework put in place allows for some justification of investments and the need for them, as well as a forward-looking assessment, to be provided by the companies, of the cost of capital that companies should be allowed to earn.

5 Principles of regulation and the case for change

This section provides a high-level assessment of the performance of the electricity regulation system in TCI, and outlines some options for what an alternative system might look like.

Section 5.1 starts by illustrating principles that can be used to design an effective system of electricity regulation. Section 5.2 then assesses the performance of the existing system of electricity regulation in TCI against these principles.

Having found that the existing system ‘falls short’ on some of these principles, section 5.3 introduces some potential options for regulatory reform of the TCI electricity sector, which appear to be more consistent with the principles. While some of these options are possible within the existing regime, and could be pursued in the shorter term, others would require more extensive reforms and/or may be longer-term in nature. How these sorts of reforms, if taken forward, could be introduced in practice is discussed in more detail in section 6.

5.1 Principles of economic regulation

A clear specification of regulatory principles is central to assessing the performance of the current regime. It is also important to developing a new overall approach to regulation going forward. Some important principles, which any regulatory regime should seek to balance, are set out below. While some of these are complementary, others may conflict to some extent. Therefore, there is no perfect system, and in practice any regulatory system must make trade-offs and be sensitive to the local conditions.

1) **Government policy objectives should be clearly set out and should be taken into account in the regulatory regime**—for example, government policy should be clear on social considerations (including the treatment of different types of customers in the setting of tariffs), strategic issues, and the role and funding of renewable energy sources. The regulatory regime should then ideally be designed to be consistent with these objectives.

2) **Regulation should promote the consumer interest and protect consumers from monopoly power**—electricity companies undertake ‘naturally monopolistic’ activities (or at least may inherit a position of market power); hence, regulation may be required to protect consumers’ interests. Regulation should seek to limit the potential for excessive monopoly profits to be earned—prices should ensure that the companies cover their costs, including a return on investments equal to the cost of capital. Regulation should also ensure that an adequate level of service is provided. Furthermore, regulators may be concerned to ensure that there is fair treatment of different types of customer in the setting of tariffs, which may in turn need to take account of the government policy objectives—see 1) above.

3) **Utility businesses should have incentives to improve their efficiency now and in the future**—in the absence of effective regulation, monopolies may have insufficient incentive to reduce their costs or improve their service offerings. Regulation can be used to encourage electricity companies to improve their day-to-day OPEX efficiency, and to invest in the right activities at the right time and at the right unit cost (CAPEX efficiency). The regulatory system can be designed to provide electricity companies with a profit incentive to seek cost efficiencies in the shorter term, enabling them to earn some degree of monopoly profits in the shorter term, with the benefits of these efficiencies passed on to customers in the longer term. Similarly, the regulatory system can be designed to provide the companies with incentives to improve quality of service.

4) **Utility businesses need to be able to finance their functions by recovering their costs**—utilities differ to firms operating in 'normal' markets in two important respects: the service supplied is a basic necessity (eg, consumers have little choice but to use electricity and water); and, as stated, the often naturally monopolistic nature of networks means that if a utility stops producing, there can be widespread social disruption and economic costs. The combination of these two factors means that the ongoing functioning of an electricity company needs to be protected. Tariffs need to be set in a way that enables utilities to recover their costs.

5) **Competition and/or third-party participation should be encouraged where this is both feasible and desirable**—not all aspects of utility provision, including electricity, are necessarily 'naturally monopolistic'. Where feasible, some aspects of service provision can be opened up to competition and/or third-party participation of some form. This might even replace the need for regulation of that particular aspect of service provision. Competition and/or third-party participation will be desirable if, over the medium to long term, it is likely to lead to lower costs, greater resilience, or other net benefits.

6) **Regulation should be appropriate to the setting**—in particular, in a small-island context, regulation should seek to control monopoly power and encourage efficiencies, but in a way that minimises the regulatory burden, is proportionate (in cost terms) to the benefits obtained, and is practical to implement. Regulation on TCI cannot economically replicate fully the more detailed systems of regulation implemented in larger jurisdictions.

Notably, principles 2, 3 and 4 above all concern the degree to which tariffs should be aligned with actual costs. There are some important considerations to balance here. For example, while customers should be protected from monopoly profits (principle 2), the regulator may still want to provide the companies with an incentive to improve their efficiency (principle 3), which can mean allowing the companies to make profits above their cost of capital for a period of time. Another issue is that, while utilities should be able to recover their costs (principle 4), they should also be required to demonstrate that their costs are prudently incurred (principle 3).

A corollary of the above principles for economic regulation is that an adequate institutional structure and appropriate regulatory processes need to be present to deliver against them. Failure in this area can easily undermine the legitimacy of regulation as perceived by some, or even all, stakeholders. The key features here are as follows:

7) **The institutional set-up should support the system of regulation**—the adequacy of the institutional set-up is central to make the regulatory process work and to ensure the buy-in and trust of all relevant stakeholders, including the regulated companies;

8) **The regulatory process should be transparent**—this is central to reduce risks that arise from the process itself, to allow stakeholders to position themselves appropriately within that process, and to understand the process outcomes.

As noted, the above principles can then be used to examine the performance of the existing regime, and to explore options for reform going forward.

5.2 The current regulatory regime: an assessment

The analysis in previous sections illustrates the main features of the existing regime. These can be assessed against the principles of economic regulation outlined above. This section does this under three key headings which, taken together, comprise a regulatory regime:

Policy context	+	Core regulatory model	+	Institutional set-up and transparency of regulation

Does the current regime address the key regulatory principles?

- **The policy context**—in particular, whether government policy is clear, and whether the current system of regulation adequately facilitates energy from renewable sources, and results in fair tariff structures across different customer classes.
- **The core regulatory model**—whether the existing regime adequately balances the issues of ensuring cost reflectivity and cost recovery in tariffs, while promoting efficiency and facilitating competition (and/or third-party involvement) in areas where this is likely to be beneficial.
- **The institutional set-up and transparency of the regulatory process**—in particular, the degree of independence of regulation under the current system, and the transparency of the regulatory process (including the information relayed to and from the parties involved).

5.2.1 The policy context

Promoting renewable energy

When assessed against the principles outlined in section 5.1, government policy is not clear on the role of renewable energy in TCI, and the current regulatory framework does not facilitate renewable energy. This is a potential area in which some form of third-party participation and competition could emerge. Hence, the current regime is also inconsistent with the principle of encouraging competition and/or third-party participation where this is efficient (see also the discussion in section 5.2.2 below).

The existing legislation and regulatory framework is not conducive to permitting new electricity suppliers to generate electricity from renewable sources in the franchise area of a public supplier. This is because, at present, other electricity generators are not permitted to feed any electricity generated into the main grid. In addition, the existing public suppliers appear to have insufficient incentive to develop renewable generation themselves. This could derive from the fact that companies consider that, within the current regulatory process, it would be difficult to achieve an adequate return on investments in renewable sources if the costs of renewable energy are higher than the avoidable costs of not supplying the electricity from the existing diesel generating sets.

As indicated in section 3, in TCI electricity from renewable sources (wind and solar, in particular) could be an option to increase differentiation in the generation mix, and reduce the dependence on diesel generation, should wholesale diesel prices faced by TCI continue to rise. However, while work has been undertaken on renewable energy in TCI, at present it is not clear what the government policy is in this area.

The lack of clarity and incentives for energy suppliers (existing and potential) to supply electricity from renewable sources is a shortcoming that should be addressed if this source of energy is to be developed. In addition, the regulatory implications of a policy on energy from renewable sources would need to be clarified (eg, how would the renewable CAPEX be treated in the context of the tariff-setting).

Tariff differentials between customer classes

The tariff structures of both Fortis TCI and TCU provide for base-rate differentiation by customer class. This differentiation may or may not reflect differentials in the companies' actual costs involved in serving those classes (see section 3.1.2). What is noteworthy, however, is that government policy on social considerations in tariff-setting, and the impacts on different customer groups, is not yet clear.

In addition, the existing legislation and regulatory framework do not seem to prevent the electricity companies from unduly discriminating among customer classes, nor do they seem to require the companies to provide justifications for any tariff differential. Going forward, any regulatory framework should require an assessment of the basis for tariff differences among customer groups. It is also of note that the current base rates are as set by the Governor at takeover (in the case of TCU) or as approved subsequently (in the case of PPC). The companies have limited room to deviate from the charges prescribed for each customer class, without seeking a rate review.

5.2.2 The core regulatory model

Tariffs and alignment with costs

In principle, the tariffs as set out in the 1998 Ordinance, are aimed at allowing the supplier enough revenues to cover the costs of supplying electricity in TCI. As noted in section 3.1.1, these costs include OPEX, depreciation and a reasonable profit margin. The Ordinance also outlines a procedure for the review of the rate initiated by either the Governor or the company. Lastly, the Ordinance indicates that tariffs can be adjusted to reflect the changes in fuel prices compared with the levels assumed in the base rate.

As noted, the base-rate component reflects the unit capital and operating costs, including an assumption of fuel costs ($0.9 or $1/gallon) in the 1980s. Changes to fuel costs (ie, departures from the level of charges embedded in the base rate) are dealt with separately in the tariff (ie, through the fuel cost adjustment). The base-rate component is also likely to be set at a level that reflects an assumption on electricity consumption at the time it was established, such that, on average, the unit rate multiplied by the volume of electricity sold allowed the company to recover all its costs, with the exception of the fuel cost variations from $0.90 or $1.00 per gallon.

The base rates for TCU have been at the level introduced in the 1986 takeover agreement. Although Fortis TCI base rates have been reviewed since the takeover agreement, as explained in section 2.2.2 this has resulted mainly in changes to the tariff structure. By fixing the base rates in nominal terms at a level based on assumptions in the late 1980s about the unit costs of electricity, and the fact that per-customer demand of electricity has changed, the level of revenues from the base rate is likely to diverge significantly from the costs, even if diesel actually cost $0.90 or $1.00 per gallon.

In addition, the fuel cost adjustment relies on a conversion rate (to translate the cost of one unit of fuel into a unit of electricity), which has remained fixed, while the efficiency of the diesel generators being used has increased. This is likely to result in the revenues to compensate companies for increased fuel costs exceeding the actual increase in fuel costs.

The overall result is that the tariff structure (base rate and adjustment for fuel cost changes) is now unlikely to reflect the cost structure it is supposed to mirror. It may be that the various divergences from costs cancel each other out, so the overall level of tariffs is more aligned with costs (see section 4). However, such an outcome would be accidental, and would be unlikely to hold at other levels of diesel costs.

Quality of service and customer engagement

The existing legislation and regulatory framework do not require the companies to engage with customers and understand the level of service they expect to receive, the level of service that they are prepared to pay for, and/or impose certain minimum guaranteed level of service.

Customers perceive reliability of supply as fairly high. At the same time, they perceive that tariffs are too high. In the first instance this would point to tariffs being above what customers are willing to pay. However, with a lack of customer engagement, which would be aimed at understanding both the desired level of service and what drives the perception that tariffs are too high, it is not possible to determine whether the company has 'gold-plated' the service (through excessive investment), or whether customers have concluded that the firms are making monopoly profits (in which case, customers may believe that they can have the same level of supply quality at lower prices).

In addition, probably due to the lack of obligations or incentives to improve on the level of customer service, customer care (eg, response to queries, etc) is perceived to be poor.

Promoting efficiency

The existing legislation and regulatory framework do not require the electricity companies to justify their expenditure on an ongoing basis, nor does it require the regulator to scrutinise the level of efficient OPEX.

All that is set is the price, and, at least in theory, that price is set with respect to the company's costs.[97] The wording in the current Ordinance is that, should a rate review take place, the Governor should consider what constitutes a 'reasonable' return before approving any rate changes (see section 2.2). Potentially, this could include an assessment of whether historical costs have been incurred efficiently. However, it is not at clear that the companies hold this interpretation of what constitutes a reasonable allowed return.

The lack of regulatory incentives to increase operating efficiency is likely to have contributed to the TCI electricity companies' performance. A simplified analysis of labour productivity of both Fortis TCI and TCU would indicate that their performance is broadly in line with the industry average. However, it is also likely that both companies have scope to reduce their controllable OPEX and catch up with the most efficient companies in the region.

The existing legislation and regulatory framework do not require the electricity companies to provide an investment plan to the Government or regulator in order for them to scrutinise the plan and its justification. The plan does not need to be consulted upon or made public. At least in theory, as a consequence the companies can invest and expect that a reasonable return will be allowed on those investments without the need for, or the usefulness of, the investment being scrutinised by regulator, or consulted on with stakeholders.

Overall, the lack of regulatory scrutiny and need for justification of investments, coupled with companies' expectation to earn a reasonable profit on their activities, are likely to be key drivers of any overinvestment in capacity. That said, the companies do undertake investment planning to various degrees. In particular, as noted in section 3, Fortis TCI undertakes both business planning and internal benchmarking of its activities. Section 5.2.3 discusses this further.

Enabling companies to finance their operations

The existing legislation and regulatory framework require that electricity companies are allowed tariffs that include a reasonable profit. This requirement, however, has not been transposed into a methodology to calculate the level of reasonable profit and update it over time. Accordingly, what a reasonable profit level is has not been established. As illustrated in section 2.2.3, the only reference to an allowed return was that in the takeover agreement for PPC, and its applicability in subsequent regulatory periods is being disputed.

In practice, the base rate has remained broadly fixed for both companies over time, and the interaction between cost and demand changes has resulted in volatility in ROCE, as

[97] As noted above, in practice, the current overall tariff structure (comprising the base rate and fuel cost adjustment) is unlikely to mirror the current cost structure, as the parameters have become out of date. If there is overall alignment of tariffs with costs, this is likely to be accidental rather than by design.

measured from the accounts.[98] High returns were achieved by the TCI electricity companies in the first years of the period considered in this report (ie, prior to 2008), and appear to be above what would have been a reasonable return on investment, as established by the competitive benchmark (ie, the cost of capital reported in section 4). In more recent years the levels of return have reduced and are more in line with the benchmark level. If tariffs are not reviewed for a number of years, it is unclear what the impact on companies' returns are likely to be going forward (ie, it is possible that actual returns fall below the cost of capital).

In addition, as uncertainty in the regulatory process used to set the allowed rate of return increases the regulatory risk, this could itself translate into investors requiring a higher return on any future investments that they may be required to make. Going forward, this may affect the capacity of a stand-alone TCI company (ie, not part of a group that might find it easier to raise finance) to attract finance if expected returns are not perceived as adequate.

In order to make it easier for TCI companies to have access to finance going forward, it would be important that a clear methodology to set the allowed level of returns is adopted and implemented, together with a process to update these estimates.

Encouraging competition

The existing licensing system (under section 4 of the Ordinance) grants public suppliers an exclusive right to generate and supply electricity to any person within the area specified in the licence. This effectively establishes a regional monopoly for a vertically integrated (from generation to consumption) electricity supplier within this region, and therefore entry by other operators to generate electricity for sale is not possible in general.

However, the Ordinance does contain key exceptions to the limitations on the generation of electricity by third (non-licence) parties. In particular, generation using wind and photovoltaic plants; electricity generated for vehicles and vessels; generation used in case of the breakdown of the electricity supply under the public supplier's licence; electricity produced when carrying out construction work; or electricity generated using a technology as prescribed by the Governor are all permitted. In addition, the Ordinance allows for a private supplier's licence, which is for self-supply.

The Ordinance seems to indicate that an operator using wind or solar technologies could enter the public supplier area and generate electricity. However, even if this interpretation were correct, the Ordinance does not provide a clear illustration of how the entrant status would be implemented or how it would be allowed to operate and interact with the other parts of the electricity supply system.

It is important to note that the sector is likely to be too small for any future benefits of general vertical separation to outweigh the costs. Indeed, it is also of note that Castalia, in a recent report on the future options for the Jamaican electricity sector (a much larger jurisdiction), notes that vertical integration should be retained there.[99] If government policy moves towards promoting the development of energy generation from renewable sources, in that context the entry of third-party competitors may take place. However, this would be more an effect of government renewables policy than government pursuing greater competition per se.

5.2.3 The institutional set-up and the transparency of the regulatory process

The current institutional set-up

The existing legislation outlines a regulatory framework in which the decisions are ultimately taken by the Governor, and therefore the regulatory system is not independent of the political process. This potentially exposes the companies and their investors to arbitrary decisions (eg, clawing back profits perceived as excessive, taking initiatives that cause the stranding

[98] These are not the only reasons why ROCE has been volatile.
[99] Castalia (2011), 'Options to Bring Down the Cost of Electricity in Jamaica', June 23rd.

the company assets, etc) compared with jurisdictions where the regulatory system is (more) independent from direct government interference.

A regulatory framework exposed to political risk will tend to be lacking in credibility when committing to the remuneration of long-lived assets. Investors will either not invest or demand higher expected returns.

In case of TCI, over time the companies have applied for rate reviews to obtain increases in tariffs that reflected the changed economic and operating conditions since the time of privatisation. In general, tariff increases have not been granted and the companies' perception is that the basis for these rejections has not been clarified.

Overall, the regulatory system in TCI appears to be prone to being perceived as increasing the regulatory/political risk for companies involved.

Transparency of the regulatory process

A pillar of economic regulation is the transparency of the regulatory process so that all stakeholders can easily understand the process and decision-making. The current lack of transparency of the regulatory process in TCI appears to affect all key stakeholders.

– Consumers do not understand the charging system and why prices go up; however, under the existing regulatory regime, there is no obligation to explain this to them.

– The Electricity Commissioner or government have, under the existing legislative arrangements, limited general powers to request information from companies (namely audited accounts and rate submission). The provision of information—for example, on capital programmes—is not mandated. Overall, this could result exacerbate the asymmetry of information between the company and the Electricity Commissioner or government.

– Companies do not clearly understand how decisions are made at rate reviews. It is perceived that too much discretion is left with the Governor.

Expanding on the first point, and as discussed in section 2, consumers in TCI do not currently understand why their electricity bills are high. The companies should do more to engage and communicate with their customers on these issues. In addition, under the existing framework, the companies should do more to communicate and consult with consumers on their investment proposals, and the rationale for the investments. This would be voluntary, but would be in the companies' interests. These and other potential changes that might be possible through incremental alterations to the current regime are discussed further in section 5.3.

There are also issues concerning the information provided to the Electricity Commissioner and to the Governor. At present, the only information that is required from the companies under the existing regime (and under the legislature) is:

– information related to fuel costs and the fuel cost adjustment, to enable monthly monitoring by the Electricity Commissioner;

– annual audited financial statements under Sections 43 and 44 of the Ordinance;

– the annual (regulatory) return, as set out under Sections 43 and 44 of the Ordinance, which were expanded into Schedules as a means for the companies and Governor to assess whether a Section 34 rate case would be required;

– information as may be required by the Governor or the appointed Commissioner for the purposes of undertaking a rate review (Sections 33 and 34 of the Ordinance).

On a voluntary basis, the companies have also provided presentations and further information to the Commissioner and the Governor. For example, TCU has submitted a report on its plans for renewable solar/wind energy. Fortis TCI has provided a series of presentations to the Governor and Electricity Commissioner on its current CAPEX programme and future plans.

However, there are other sources of information that the companies might share with the Commissioner (albeit, under the existing regime, on a voluntary basis). As discussed in section 3, Fortis TCI, in particular, currently compiles internal information on business planning, performance monitoring and on its future plans to benchmark its activities. It is not clear that the Electricity Commissioner has asked for this information. Such information could in principle also be useful for regulatory purposes.

Lastly, under the current regime, as discussed in section 2, the companies are not clear how the information they do now supply is actually used. There are also issues concerning the decisions made by the Governor on whether Section 34 rate cases should be initiated, and the companies have voiced concerns that the reasons why these cases are not taken forward are not always made clear.

5.3 Moving forward: some options for regulatory reform

This section sets out, at a high level, options for regulatory reform that could address the issues in the existing regime discussed in section 5.2.

In what follows, potential changes to the regulatory framework are discussed, according to each of the principles outlined in section 5.1. The potential changes, which in some cases might be introduced under the existing legislation, and in others would require new legislation, are again grouped under the three headings used in section 5.2:

Policy context + Core regulatory model + Institutional set-up and transparency of regulation

What options exist for better addressing the key regulatory principles?

– **The policy context**—this includes options to facilitate energy from renewable sources; and options in relation to achieving cost-reflective and/or ‘fair’ tariff structures across different customer classes.

– **Core regulation**—this includes options that could be pursued under the existing regime, using voluntary initiatives under the existing legislation, versus more fundamental reforms to the core regulatory model (including a price cap regime, coupled with a building-block approach).

– **The institutional set-up and transparency of the regulatory process**—this includes options regarding the degree of independence of regulation, resourcing issues, and information requirements. Also discussed is the potential for stakeholder engagement in the process, and the possibility of establishing a fund to deal with hurricane events.

As will become clear, taking forward any of the options discussed will involve looking at the detail. This section summarises the array of options available. Expanding on this, section 6 looks in more detail at what some of these options could involve in practice.

5.3.1 The policy context

Going forward, the TCI Government would need to confirm its policy on renewable energy and social and rebalancing issues in tariff-setting. The regulatory framework would then need to be consistent with this policy.

Promoting energy from renewable sources

It will be necessary for both policy and the regulatory framework to provide an environment that supports renewable energy, where this is likely to be beneficial and cost-effective. The World Bank has identified that, across various Caribbean islands, a number of renewable initiatives are cost-effective and viable, but that cooperation between islands would improve viability still further (not least since it can increase scale, reduce the intermittency problem, and reduce capacity margin requirements).[100]

However, as noted previously, TCI is somewhat more remote to the regional interconnection initiatives being considered, for example, in the Eastern Caribbean. Therefore, given the circumstances, TCI is likely to need to develop a policy of its own, but nonetheless taking account of best practice in other Caribbean jurisdictions.

Before 2011, there was not strictly a government-led energy policy on TCI. Therefore, in 2011, Castalia was commissioned by the TCI government, through the Department of Environment and Coastal Resources (DECR), to develop an Energy Conservation Policy and Implementation Strategy. The Castalia report highlighted measures that could be taken forward on TCI on its own, which would also affect the economic regulation of the sector. In that report the consultants outlined the two key strategies:

– **promote utility-scale renewable energy**—by creating rules and incentives that make utilities and companies assess and implement large renewable energy projects that are cost-effective;

– **promote distributed-scale renewable energy**—by establishing rules, and incentives, that allow customers (and others) to implement smaller-scale renewable energy projects that can deliver cost-effective power, while not increasing the overall cost of power.

As a first step, a decision by the government is still required on what the TCI renewables policy actually is. For the purposes of this report, it is assumed that it is as per the Castalia report. What needs to be recognised, however, is that, for the foreseeable future, diesel will play a large part in the energy mix on TCI, and that, moreover, escaping this legacy is more about diversity in generation than about carbon emissions.

In addition, if a building-block approach to regulation were introduced in future (as part of a price cap approach—see below), any carbon tax—if introduced—would be likely to be passed on to consumers in prices. In effect, it would be included as a relevant element of the costs projected for the utility. If introduced, the carbon tax element should be identified clearly on consumer bills.

In this context, Oxera has identified shorter- and longer-term measures that might be undertaken.

– **Shorter-term measures**: measures that can be implemented without major changes to the industry set-up (eg, changes to the tariff structure to incentivise energy efficiency by customers).

– **Measures for longer-term consideration**: these comprise a menu of options that could be explored and their feasibility assessed before implementation is pursued (eg, the introduction of feed-in-tariffs).

[100] For an analysis of individual solutions versus regional Caribbean solutions to sustainable electricity, see Gerner and Hansen (2011), op. cit.; and Nexant (2010), op. cit.

As such, it is important that the TCI Government clarifies its policy and outlines a plan to implement that policy. The regulatory framework would then be able to take account of this policy.

These options, and the issues involved, are discussed further in section 6.

Tariff differentials between customer classes

As noted, larger users (especially large hotels, in the case of Fortis TCI) receive a discount at present on the basic tariff relative to residential customers. It is common across Caribbean jurisdictions for charges to larger users to be discounted relative to residential users. The reasons are often to promote tourism and the commercial sector. However, discounts on these charges do not always appear to be cost-reflective.

In theory, there could be valid reasons why charges to larger users might be discounted. Cost-justified discounts might stem from:

- serving a single billing point rather than multiple billing points, so making savings in administration and metering costs;
- saving costs owing to economies of scale in generation in serving larger users. (This is unlikely on TCI at the current scale, given the size of the units on TCI, and since as much of the costs of generation are fuel-related);
- savings in distribution costs owing to off-take at a higher voltage or at an earlier point in the network. (This is perhaps less relevant for TCI, given its size and the voltage levels used).

In addition, the increased demand from some customers due to discounting may enable fixed costs to be spread over higher volumes, reducing bills for smaller users. However, this needs to be weighed against the bringing-forward of investment from pressure on demand from larger users, which increases costs.

Section 6 discusses in more detail the tariff rebalancing (and rate increase) proposals currently being put forward by Fortis TCI.

In general, for tariff differentials to be scrutinised effectively by the regulator, a clear articulation of the cost differentials (if any) that are relevant and which justify the tariff differentials is needed from the companies, and the same is needed for any government policy (eg, the promotion of tourism, social issues) that is being pursued through tariff differentials. Only if the rationale for differentials is set out can the fairness or efficiency of such differentials be evaluated by the regulator.

5.3.2 The core regulatory model

The regulatory regime should ideally promote the customer interest, encourage efficiency, and enable companies to finance their operations. It should achieve an appropriate balance between placing incentives on the companies while protecting them from uncontrollable risks. The process followed should also be transparent and practical.

In undertaking reform of core economic regulation, a spectrum of options could be pursued. Put simply, however, there is a choice between:

- **incremental changes**—pursuing changes under the existing rate-base regime, and under existing legislation;

- **more fundamental changes**—introducing more far-reaching reform, such as price cap regulation, coupled with a building block approach, which would require changes to the existing legislation.

The issues that will affect this choice are discussed further below.

Addressing the issues under the current regime

The existing regime has some benefits in terms of TCI securing high reliability. Information is provided on an annual basis on key financial and operational issues for monitoring purposes. Radical change would also bring about costs, in terms of revisions to the Ordinance, and regulatory restructuring, hiring and training. The companies themselves would also need to adapt to any new regime. For these reasons, some measures that could be undertaken under the *current* system of regulation, and under existing legislation, have been considered. Discussions with stakeholders revealed that consumers do not understand the fuel cost adjustment, and that the regime is too prescriptive and process-orientated. Changes that could be introduced are as follows.

– **Base rates and fuel costs**—could be updated to include a best estimate of fuel costs at the start of each financial year.

– **Fuel cost adjustment and efficiency**—the fuel cost adjustment could factor in a more realistic and up-to-date assumption on fuel-burn efficiency, and could be communicated more effectively to customers. The companies could also publish, in advance, what bills are likely to be in the coming months, to help consumers budget better.

– **Investment assessment**—a voluntary arrangement could be introduced whereby the Electricity Commissioner can review (and advise on the prudence of) the investment plans of an electricity company before large investment is committed.

– **Operating and performance efficiency**—the companies could volunteer to share with the Commissioner evidence of their initiatives to improve efficiency.

– **Customer engagement**—the companies could sign up to a voluntary arrangement to undertake engagement with their customers on investment plans before pursuing these.

– **Service performance**—the companies could also sign up to developing customer-facing service measures, and to publish their performance on these on a regular basis.

These potential changes are discussed in more detail in section 6. Such changes may not radically alter the incentives present under the existing regime, for example with respect to efficient levels of investment or OPEX. Many of these changes would rely on voluntary initiatives, which the companies may or may not sign up to.

Addressing the issues using a form of price cap regulation

The current regime does not appear to achieve an appropriate balance in promoting the consumers' interest, encouraging efficiency and enabling companies' to finance their functions. Going forward, a reformed rate-base approach could be used to ensure that electricity companies do not make excessive 'monopoly' profits—significantly above their given cost levels—for an extended period of time, thereby protecting consumers to some degree. Moreover, under the existing rate-base approach, the parties may agree to changes to the regulatory process that allow wider customer engagement, and more in-depth regulatory scrutiny of investment, thereby encouraging efficiency.

However, under the current rate-base approach, the companies are of the view that they should be able to earn a 17.5% (Fortis TCI) or 15% (TCU) return on all their capital employed, irrespective of whether that capital has been efficiently deployed or how efficient they are in their day-to-day operations. The current process has become marred with disputes around this issue. As a minimum, if a rate-base approach is maintained, clarification would be required on the status of the 17.5% and 15% figures.

In any case, legislative changes might be needed to embed customer engagement and quality of service in the regulatory decision process and outcomes. Legislative changes could also be required to provide powers for the regulator to examine and approve investment proposals. Moreover, given the multitude of concerns highlighted in section 5.2, small modifications to the existing rate-base regime might not provide adequate incentives for companies to reduce their OPEX when this controllable, or to plan investment efficiently.

A potential alternative is that, accompanied by legislative changes to support it, price cap (or 'RPI – X') regulation could be introduced. This has fundamentally different incentive properties to the rate-base approach. Typically forward-looking, price cap regulation could incentivise the companies to become more efficient, while revealing information on efficient costs through observed company behaviour over time. It would, however, still need to be accompanied by an adequate pass-through mechanism to deal with variations in fuel costs. Box 5.1 discusses what is often involved in a price cap regime.

Box 5.1 Simplified description of price cap (RPI – X) regulation

Price cap regulation requires a best estimate of future costs to be projected, including an estimate by the regulator of the returns required by providers of finance to invest in the company (ie, the company's cost of capital). This determines the company's revenue allowance.

Importantly, prices are then set out and fixed for a period of time (eg, N = five years)—which remain in place regardless of what the costs turn out to be for the business over subsequent years.[101] In this way, the utility faces a 'fixed-price contract' to deliver a required set of outputs to consumers. The business then has an incentive to outperform (beyond that assumed in price limits) by delivering further efficiencies. This is because the business retains the benefits of this outperformance—in the form of additional profits—until prices are re-set to actual costs at the next price review:

– **Outperformance**—If the utility outperforms the regulator's assumptions on OPEX or CAPEX efficiency (or on financing costs), embedded in the prices set, the utility keeps these additional profits (over and above the cost of capital).
– **Underperformance**—by the same token, if the utility fails to perform, and its costs escalate materially from those assumed, it bears the risk of profit underperformance (where returns are lower than the assumed cost of capital).

An additional benefit of the price cap approach is that, over time, the companies should reveal their efficient costs. This is important, given the asymmetry of information between the regulator and the company.[102]

Once the N years of the price control are over, if required the benefits of outperformance can be passed on to customers. As such, the ability of the utility to retain excess profits obtained from outperformance in the short run is a quid pro quo for ensuring a more efficient sector, and passing on these benefits to consumers in the long run. This is why RPI – X regulation requires a sufficiently independent economic regulator that can resist any calls for reduction in tariffs once the price controls have been put into place. Any claw-back would damage incentives, and would not benefit consumers in the longer term.

A potential problem with pure RPI – X price caps is that they can expose the utilities to risks with respect to costs, over which they have little control. This might simply increase the cost of capital without any beneficial incentive effect. In addition, care must be taken in monitoring the outputs delivered by the companies. An efficiency saving is not equivalent to cutting costs by cutting corners. As such, it is possible to bolt on additional mechanisms to the RPI – X regime, as follows.

– **Uncontrollable costs (risk-reducing)**—some elements of pass-through can be adopted for costs that lie beyond the control of the utility, and which are significant and unpredictable. (Changes in the price of diesel would fall into this category.) However, controllability can be a matter of degree, and it is important to bear in mind the extent to which the utility is able to mitigate certain external cost changes.
– **Quality of service (reward-increasing)**—quality of service incentives might be introduced by publishing information on company performance, providing additional (or less) allowed revenue

[101] Notwithstanding this, in each year the business is allowed to pass though to consumers charges changes in costs stemming from changes in inflation (or RPI), which lie beyond its control.
[102] Since, in practice, the regulator faces an 'information asymmetry problem', in that the company has a better idea of the scope for cost reductions than the regulator, a benefit of price cap regulation approach is that, through the workings of the incentives present, the company reveals its outturn efficient costs.

for good (or poor) performance, and/or through compensation payments to customers in the event of failures involving individual customers. In addition, companies might be required to engage customers as part of their planning processes and be rewarded (penalised) for succeeding (failing) to do so (see section on transparency, below).

Price cap regulation, if applied, should be adapted to the specific context concerned.

Source: Oxera.

The way in which price cap regulation might realistically be applied in TCI cannot and should not mirror the full host of detail and information requirements often observed in larger jurisdictions implementing this regime (such as the UK, and certain US states). Rather, the approach should be proportionate to the situation faced in TCI, in terms of the scope of regulation, the information requirements, and who does what. In practice, this will mean addressing what is typically involved in setting up a price cap regime, but always bearing in mind the TCI-specific context.

Notably, there is increasing interest in the role of price cap regulation in the Caribbean. As will be discussed in section 6, CARILEC generally supports price cap regulation over cost of service (rate base) regulation, and TCU has also highlighted that a form of price cap regulation was successfully introduced in Grenada. However, TCI is small and more remote than most other Caribbean jurisdictions, and it may not be possible to replicate fully the institutions and form of price cap regulation introduced elsewhere in the Caribbean.

Further elements to consider in applying a price cap regime, which are discussed further in section 6, would be the risk–reward balance in the price control, including;

– the nature of the RPI – X fixed-price contract, including the inflation index that prices might track;
– additional mechanisms for uncontrollable costs (risk-reducing);
– additional mechanisms for quality of service (reward-increasing).

When applying the above, major considerations include the degree of independence of the regulator, the resources available (to the regulator and the companies), and the availability of data. Another important issue is whether it is possible to measure RPI adequately on TCI.

Addressing the issues using a building-block approach

If a price cap regime were implemented, an important step would be for the regulator to assess the revenue that a utility should be able to recover through customer bills over the N future years over which the price cap applies. This needs to be determined in a way that will enable the companies to cover their costs, provided that they behave efficiently. One way of doing this is to use a 'building-block' approach to determining the revenue allowance.[103]

The first step under this approach is to determine the efficient costs, both the OPEX and CAPEX, which the utility is likely to face over the next N years. This is then converted into a pot of revenue—a revenue allowance—that the utility is allowed to recover from its customers over each of the N years.[104] In this conversion, OPEX and CAPEX are treated differently in the building-block approach. In particular, CAPEX is lumpy in nature, and so to reflect this in prices directly would lead to unstable bills. Moreover (unlike OPEX) CAPEX is not the actual cost faced by a utility in each year—rather, the costs to the utility are the return of, and return on, capital it must repay in each year, having borrowed from investors in order to undertake the CAPEX. Box 5.2 explains.

[103] It is not strictly necessary to use a building-block approach to implement price cap regulation, but in practice this approach is often used.

[104] Notably, under ex ante RPI – X regulation, the regulator has the power to set prices, and, therefore, typically has the power to assess the appropriate CAPEX and OPEX for the electricity business for the forthcoming N number years. How it does this varies from case to case (as discussed later below).

Box 5.2 Simplified description of the building-block approach to price controls

OPEX and CAPEX tend to be treated differently in arriving at a revenue allowance as part of a price cap regime.

OPEX comprises day-to-day expenditures, such as labour and materials (and, in many contexts, maintenance). The regulator typically looks at the costs incurred to date, and takes account of the upward and downward pressures on these costs that are likely to emerge in future. An efficiency target is then applied to the costs, which feeds straight through into the revenue allowance for the next N years.

CAPEX—the regulator must also forecast efficient future CAPEX, which can be somewhat more difficult than forecasting OPEX. CAPEX is also treated differently to OPEX in setting the revenue allowance.

– CAPEX is comprised of more lumpy expenditure, in which investment takes place in long-lived assets. Reflecting CAPEX directly in the revenue allowance would result in volatile bills.
– The benefits of CAPEX are spread between current and future customers. It would be unfair for current customers to pay exclusively for assets that will benefit future customers.
– It is also assumed that CAPEX is funded through shareholder equity and debt, with this repaid over the longer term to investors. The costs to the utility are not therefore the CAPEX per se, but the costs of financing the CAPEX in each year (akin to the costs to a consumer of a house not being so much the purchase price, but the stream of repayments of principle and interest on the money borrowed to buy the house in each month).

For all these reasons, CAPEX does not tend to be reflected $1 for $1 in the revenue allowance in the year that it is incurred. Rather, the cost to the business is assumed to be in the form of repayment of the principle borrowed (return *of* capital) and a return *on* the capital to finance the investment.

The components are determined as follows.

– The **regulatory asset base (RAB)** can be thought of as the value, from a regulatory perspective, of the business. CAPEX additions that are forecast (and approved by the regulator), for each of the N years, are added to the RAB. The most difficult aspect is to determine the opening RAB for the first time a price control is applied. This becomes a more automated process thereafter. For example, if the RAB in Year 0 is determined to be $90m, and $10m of CAPEX is added in Year 1, the closing RAB in Year 1 is $100m (before depreciation is subtracted—see below).

– **Return of capital**—in each of the N years, a 'depreciation charge' is included in the revenue allowance. This is subtracted from the RAB in each year. Depreciation is often calculated using assumptions on the remaining life of assets already contained in the RAB, and the asset lives of new CAPEX added to the RAB. For example, if the $10m of new CAPEX in Year 1 has an asset life of 20 years, the depreciation charge for this element in Year 1 would be $0.5m. Assuming existing assets in the RAB have a total depreciation charge of (say) $7m, total depreciation for the year would be $7.5m. This would mean that the closing RAB (after depreciation) would be $92.5m.

– **Return on capital**—in each of the N years, a charge for return of capital is reflected in the allowed revenue. This is calculated as the RAB multiplied by the assumed WACC (%). For example, if the closing RAB is $92.5m in Year 1 and the WACC is 10%, the return on capital included in allowed revenues for Year 1 would be £9.25m.

Use of these components in this way is usually referred to as the 'building block' or 'RAB/WACC' approach to regulation.

Source: Oxera.

Section 6 describes how a simplified version of the building-block approach might be introduced on TCI, were a system of price cap regulation to b implemented. Key issues again are the resources available (to the regulator and the companies), and the availability of data.

As noted, price cap regulation does not have to involve a building-block approach. However, it does perform a number of functions (as described in Box 5.1) in terms of smoothing the impact of CAPEX between current and future customers, while providing some certainty to investors that (efficient) future CAPEX will be recovered in prices.

5.3.3 The institutional set-up and the transparency of the regulatory process

As discussed, the institutional set up and the overall transparency of regulation could—and should—be improved. Although there are a number of options for doing so, the preferred one will be determined by the system of regulation that is introduced (and whether this involves incremental changes to the existing regime or more fundamental changes), and by what is practical for TCI, given its small size and remoteness.

The institutional set-up

The institutional framework on TCI could be significantly strengthened to improve the way in which regulation operates, and to establish any alternative system of regulation (such as price caps), if introduced.

As discussed in section 2, at present the Electricity Commissioner has limited powers to collect information on the companies, or to monitor the fuel cost adjustments that they put forward. The Electricity Commissioner rests within a government department. Under Sections 33 and 34 of the Ordinance, the Governor has ultimate power to determine whether there should be changes to tariffs through modifications, within the existing legislation, to regulations. This includes changes to the level of base rates, charges for different customer groups and islands, and the workings of the fuel cost adjustment.

The electricity companies are concerned that regulation is not independent from short-term political influence. There is indeed a case for greater independence of economic regulation on TCI, in particular if a more honed system of incentive-based regulation is to be introduced (such as price caps).

The delegation of regulatory powers to an independent organisation can resolve commitment problems (such as removing short-term political influences); can assist in developing technical expertise; and can enhance rule-making relative to a situation where non-specialist government staff retain this responsibility.[105] Greater independence in tariff-setting would make the process more certain for the companies, and potentially enhance efficiency incentives.

However, independence of economic regulation and its benefits may be more difficult to secure on a small-island economy because the availability of relevant skills may be limited, and the arm's-length relationships may be more difficult to sustain.[106]

As regards resourcing, a difficulty facing small-island economies—including TCI—is the fixed cost associated with maintaining a core of regulatory staff and providing the resources they need to discharge their duties. Given the relatively small population served, the overall costs of regulation will tend to be higher in a small jurisdiction than in a larger one. In addition, the human resources with the required qualifications and experience may not be readily available. Economic regulators in larger jurisdictions employ a number of full-time, skilled professional staff to perform the duties that are necessary to fulfil the regulator's statutory obligations. Smaller jurisdictions, such as TCI, may not be able to do so.

As regards independence, the complete independence of any new regulatory body—from both government and from the regulated companies—may be more difficult to achieve in a small-island setting. Individuals from the various parties are likely to interact more on a day-to-day basis than in a larger jurisdiction, where interaction tends to be more distant and more anonymous.

[105] Oxera (2009), 'The role of government in GB network regulation: is independence under threat?', *Agenda*, April.

[106] Ehrhardt, D. and Oliver, C. (2007), 'Big challenges, small states', *Gridlines*, p. 2.

In designing a new institutional regime for TCI, the guiding principle should be that the changes should deliver improvements at an acceptable overall cost. In this regard, some choices to be made include:

– the degree of independence of the regulator from government, and the ultimate powers of the regulator (eg, to set tariffs);

– whether a self-contained regulator for electricity services is introduced, or resources are shared by regulating various sectors across TCI, or with other Caribbean jurisdictions;

– whether there is a persistent regulatory presence, or one that is convened on a sporadic basis (including the role of outsourcing to external parties); and

– whether the regime is in-depth or more proportionate and 'hands-off' (including the degree to which the regime is adversarial between the regulator and companies).

The emphasis of regulatory intervention should be on *getting right the aspects that really matter*. In section 6, the above institutional design issues are discussed in more detail, under two headings: regulatory style and powers; and resourcing strategies. In addition, as part of reforming the institutional design, section 6 discusses the potential for embedding a requirement for stakeholder engagement in the process (see also transparency, below); and including separate and well-defined arrangements for dealing with events such as hurricanes

Transparency of the regulatory process

The lack of transparency of the regulatory process in TCI appears to affect all key stakeholders: consumers, government and companies. A revised framework could be designed such that all stakeholders are clear about their involvement and how to provide their contributions effectively, and then understand the decisions made.

As noted above, even within the current rate-base framework, transparency could be improved—for example, in relation to the operation of the fuel cost adjustment, and in the Commissioner having a more proactive role in assessing the companies' investment proposals before any large projects are undertaken.

Transparency is even more important if a form of price cap regulation is likely to be introduced. Otherwise, the main benefit of this form of regulation—the incentives for the companies to achieve efficiencies in their OPEX and CAPEX—could be lost. In addition, the perceived regulatory risk that lack of transparency could bring may raise the companies' financing costs.

There are a number of areas in which the regulatory body could help to ensure that the framework is transparent (and which are particularly important in a price cap approach).

– **Clarity on the process—**from the outset the regulator would need to make clear the timeline for making decisions, consultations and any other relevant milestones.

– **Clarity on the methodology**—the regulator would need to make clear would need to make clear at an early stage the components of its approach (eg, the form of any price cap), and what the process would be for any adjustment to tariffs to deal with uncontrollable events.

– **Clarity on decisions**—in publishing its decision document on setting tariffs, the regulator would need to illustrate how its methodology was implemented, and how key decisions or judgements were made.

Further detail is provided in section 6 on these and other aspects of regulation (in particular, see section 6.4). An onus might also be placed on the electricity companies to improve transparency—for example, in the following ways (again, these issues are particularly important in a price cap approach).

– **Forward-looking business planning—**the companies could be required to provide a business plan that sets out their forward-looking strategy and their forecasts of CAPEX, OPEX and demand, etc.

– **Efficiency benchmarking—**the companies could be required to provide evidence at the time of the tariff-setting of their efficiency in undertaking OPEX and CAPEX.

– **Embedding customers in their decisions**—the companies could be required to engage their customers on areas of relevance to them, such as the level of service they expect (for example, exposing any trade-offs between reliability and costs).

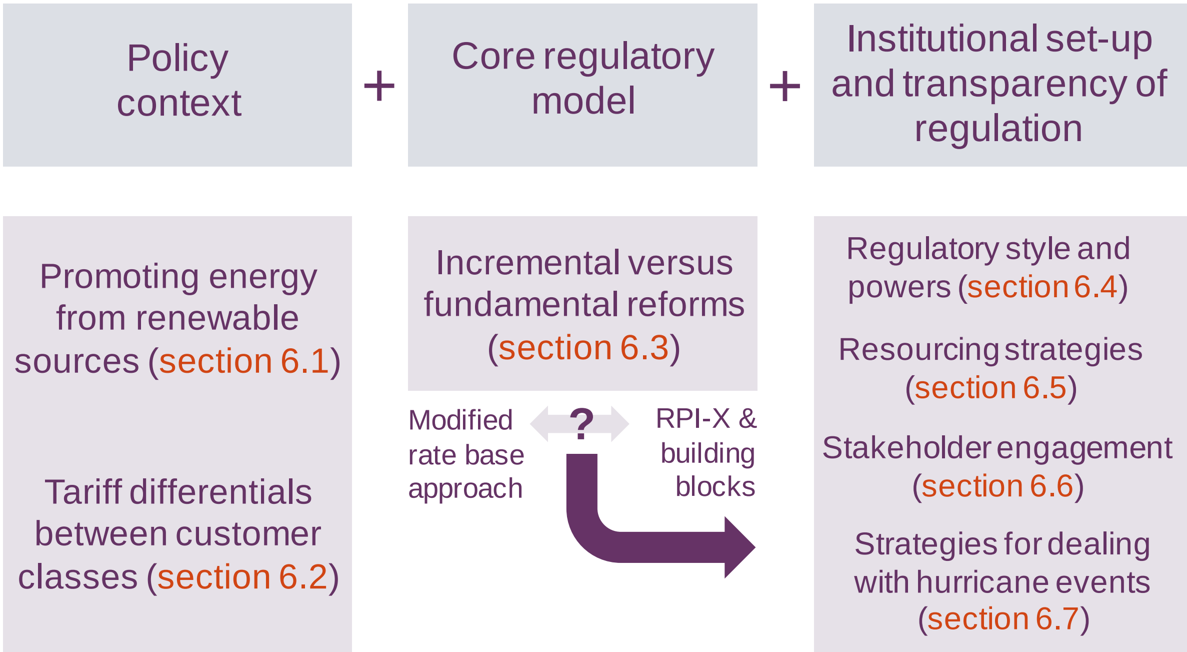
These issues are discussed further in section 6.

6 Regulatory reform options: practical implementation issues

Building on the options for regulatory reform introduced in section 5.3, this section now explores in more detail how some of the reforms discussed might be introduced in practice, and the outstanding issues that would need to be resolved.

As shown in Figure 6.1, the discussion that follows can, broadly, be grouped under the three key headings set out in section 5.3 (and 5.2), which describe the overall regulatory regime—the policy context, the core regulatory model, and the institutional arrangements/regulatory transparency.

Figure 6.1 Detailed options for reform



Source: Oxera.

Importantly, as illustrated in the middle column of Figure 6.1, a spectrum of options exist in modifying the core regulatory model, from incremental changes to the current rate-base approach under the existing legislation, to more fundamental changes such as implementing a price cap (RPI – X) approach coupled with building blocks. The latter would involve a number of legislative changes. The dark arrow in the figure shows that the decision on which regulatory regime to pursue along this spectrum will have a major impact on the institutional set-up required, including the powers of the regulator, information requirements, and resourcing.

6.1 Policy: promoting energy from renewable sources

It will be necessary for both the policy and regulatory framework to provide an environment that supports renewable energy, where this is likely to be beneficial and cost-effective. As noted in section 5.3 there are shorter- and longer-term measures that might be implemented to help promote energy from renewable sources.

6.1.1 Shorter-term measures

As a first step, a decision by TCI Government is required on what the TCI renewable energy policy is. For the purposes of this report, Oxera has assumed that it is as set out in the 2011 Castalia report on energy policy and implementation, which ruled out the introduction of renewable energy targets on TCI, as this could pose a risk of implementing projects that increase the cost of electricity in TCI (and prices to customers) for the sake of meeting a target. The report also did not specifically recommend introducing a carbon tax; rather, it found that a number of renewable technologies would potentially be viable in TCI, but that there are currently barriers to implementing these. The main conclusions of this report are summarised in Box 6.1 below.[107] Some of the analyses and recommendations in the report were questioned by Continental Economics, in a separate report commissioned by (the then) PPC.[108]

Box 6.1 Castalia report key recommendations

Key recommendations in the Castalia report, which are relevant to the current study, are as follows.

To promote utility-scale renewable energy by creating rules and incentives that make utilities and companies assess and implement large renewable energy projects that are cost-effective. This includes:

– **least-cost planning**—requiring PPC and TCU to demonstrate upfront that their generation expansion plans are least-cost;
– **fuel versus capital cost distortions**—potentially introducing a renewable energy cost recovery charge, which would be separate from the fuel charge, to recover the capital costs of renewable energy.
– **third parties**—requiring PPC and TCU to purchase renewable power from third-party suppliers when this is lower-cost and does not create risks to quality or reliability;
– **wind energy (including permissions)**—wind energy should be favoured, requiring detailed assessment of TCI's wind resources to identify the best sites; and better access to use public land.

To promote distributed-scale renewable energy by establishing rules and incentives that allow customers to implement smaller-scale renewable energy projects, which can deliver cost-effective power, while not increasing the overall cost of power.

– **Establish a grid code**—this would also ensure that anyone connecting to the grid meets standards established by the power utilities.
– **Establish a fully disaggregated, cost-reflective tariff**—this would require the current tariff to be broken down into separate cost-reflective charges for supply, connection, and the provision of back-up generation.
– **Introduce a set of feed-in tariffs**—the Electricity Commissioner should require PPC and TCU to purchase power from distributed generation units at avoided variable cost.
– **Allow PPC and TCU to recover investments in energy efficiency** by creating rules and incentives to allow the utilities to recover capital investments undertaken to increase the efficiency of their own plants or to help customers consume energy more efficiently.

Other important recommendations relate to mandatory requirements on developers and consumers. This includes mandating solar water heaters in new buildings; promoting efficient and renewable air conditioning in hotels; and promoting widespread adoption of compact fluorescent lighting. Also, Castalia recommends mandating energy efficiency in the Building Code and Development Manual—obliging facilities being built to incorporate the best materials and equipment.

Source: Analysis of Castalia (2011) report.

Arguably, in any renewable energy policy, what needs to be recognised is that diesel will, for the foreseeable future, play a large part in the energy mix on TCI. Moreover, escaping this

[107] Castalia (2011), 'Development of an Energy Conservation Policy and Implementation Strategy for the Turks and Caicos Islands', final report prepared for the Government of the Turks and Caicos Islands, March 31st

[108] Continental Economics (2011), 'Renewable energy in Turks and Caicos: an independent assessment', report to PPC Ltd.

legacy is more about diversity in generation than about carbon emissions per se. Indeed, TCI Government proposals for a carbon tax on electricity, put forward in 2011, were criticised by Fortis TCI, in part on the grounds that the carbon emissions from TCI, given its size, are miniscule compared with other countries, and since it appeared that any such tax would need to be paid by Fortis TCI without it being allowed to increase its tariffs.[109]

Moving forward, if a building-blocks approach to price-setting were introduced in future, any carbon tax introduced would be passed on to consumers in tariffs. In effect, it would be included as a relevant element of the costs projected for the utility. If introduced, the carbon tax element should be identified clearly on consumer bills.

In terms of options, some easier wins in encouraging energy efficiency on TCI would appear to be as follows:

– rebalancing between large and smaller users (in that most of the pressure on system expansion has come from the hotel sector)

– amending the structure of tariffs to encourage greater fuel efficiency. (There is currently an incentive for companies to use more electricity to pass a threshold at which they pay a lower charge for all of the electricity that they consume—this could be replaced with declining block thresholds);

– as per the Castalia report, encouraging energy appliance standards and energy efficiency; and requiring new-build hotels to install solar heating; and to use best-practice energy saving in construction.

A final decision would be required from TCI Government and the Electricity Commissioner on these issues.

6.1.2 More challenging areas for consideration

The following are further options that could be taken forward to provide an environment more conducive to renewables, although these will be more challenging to implement.

– Land access rules could be clarified to create a more certain environment for renewables at utility scale.

– Grid codes could be introduced for new independent generation, including by third-party entrants (distributed or utility scale) or self-generation by customers (distributed):

  – existing tariffs would need to be separated into various components (as per the Castalia report);

  – feed-in tariffs would need to be established, determining how much such generators are paid for electricity supplied back to the grid;

  – investment in distributed generation means that the electricity customers concerned will use less mains electricity than before, and will indeed sell back to the grid any excess generated on site. There is a choice to adopt either a ‘net metering’ or ‘net billing’ approach on TCI (see below);

  – how intermittency is treated in charges needs to be clarified;

  – there are choices on what measure of avoidable costs should be used (see below).

– The new framework of core economic regulation (discussed in section 6.3) should support renewables that are cost-effective.

[109] Fortis TCI (2011), ‘RE: proposed carbon tax’, letter to businesses on TCI, April 10th.

A decision would be required from TCI Government on all of these issues.

As regards ‘net metering’ versus ‘net billing’, under the former, the meters currently in place would simply be run backwards when electricity is sold back to the grid; hence investment in new meters is not required. Under net billing, the electricity consumed by a distributed generator, and the electricity produced by them, is measured separately. While this requires investment in additional meters, it does enable separate charges to be set for electricity sold to and electricity purchased from distributed generators by an electricity utility. This can enable more efficient charges to be set, which promote distributed renewable generation as a way of reducing overall electricity costs, rather than promoting renewables as an objective in its own right (as is done in certain European countries).[110]

Therefore, a decision is required by the TCI Government on whether to pursue net metering or net billing, taking into account policy objectives and practical issues.

On the issue of avoided costs within the grid code, if the discount offered by an incumbent to a distributed self-generator (eg, a hotel with solar panels, selling some electricity back to the grid) is based solely on short-term avoided costs (ie, the costs of diesel), this may be insufficient to ensure a critical mass of self-generation on TCI. This could be self-fulfilling, in preventing self-generation emerging in the first instance. (Put another way, if more self-generation were present, this could lead to greater avoided costs for the incumbent.)

Therefore, a decision is required by the TCI Government on the increment of installed distributed generation to be assumed in the avoided-cost calculation, and the timeframe over which this should be calculated. Here, there is a balance to be struck between taking the cost structure of the sector as is, and considering the impact on short-run productive efficiency of renewables, and the (more unknown) impacts on dynamic efficiency of renewables.

However, in TCI, generation assets would not necessarily be stranded by investment in renewables. Compared with many other forms of fossil-fuel generation, diesel plant can be bought and sold on the open market (as evidenced by purchases made by PPC a few years ago of second-hand housed units, and the sale of trailer units by TCU in 2011—see section 3.3). This should be taken into account in the treatment of avoided costs, and in terms of whether any adjustments should be made for the stranding of assets.

Moreover, the overall framework of economic regulation should support renewables in cases where these are cost-effective. For example, in its study for PPC, Continental Economics (2011) noted that the regulatory environment needs to be conducive to investment in renewables if such a change in generation mix is to be achieved.[111] The regulatory framework would need to be adjusted, to ensure that Fortis TCI could recover its costs, and to earn a risk-compensatory return on investments in renewable energy.

In this regard, as will be discussed in section 6.3, one option is to adopt a price cap methodology coupled with a ‘building block’ approach to regulation. As part of this approach, the inclusion of investments in renewable energy in the RAB would go some way to creating some certainty regarding cost recovery, if the incumbent electricity companies invest in renewables. Diesel generation is fuel-intensive, and involves some upfront outlay, but also material ongoing OPEX to pay for fuel and maintenance thereafter. In contrast, utility-scale renewables, such as wind, involve large capital outlays upfront but limited OPEX and maintenance thereafter. A problem with the current regime is that it is focused on remunerating companies for the cost of fuel, and does not explicitly consider or commit to funding forward-looking investments. The companies, in turn, may be unwilling to invest in renewables if they are uncertain that they can recoup their costs and earn a return, through future charges spread over the lifetime of the assets. The RAB mechanism, as part of a new

[110] See, for example, Castalia (2011), op. cit.

[111] See Continental Economics (2011), op. cit.

RPI – X framework, would overcome this to some extent, since there is an explicit forward-looking mechanism for funding investment, and for remunerating it in future. If the regulator can commit to the RAB, this deals largely with the issue of recoupment.

In addition, however, the following may need to be considered in the regulatory approach.

– How planned renewables capacity would interact with new powers for the regulator to review CAPEX plans, consider whether third parties have been consulted, and approve the incumbents' investments:

  – the RAB approach would improve certainty, but the degree to which the regulator signs off and guarantees that the investment would be remunerated in future needs to be clarified;

  – 'prudent and fair' conditions could be devised in this regard, developed in agreement between the regulator and company.

– Whether, as a separable project from ongoing investments, there should be a separate price control 'account' applied to utility-scale renewables:

  – this could include a higher allowed return on capital than for other investments, in order to improve the risk–reward trade-off under a fixed price cap;

  – consideration may also be given to whether a longer price control period should be applied in the case of renewables, to improve the prospects of cost recovery, and for the retention of outperformance;

  – whether the form of control should be modified to reflect the risks of renewables versus other investments. If there is to be risk-sharing with consumers, this would lower the required return.

– If included within the same price control as other investments, consideration needs to be given to how utility-scale renewables interact with other parts of the same control:

  – renewables would result in lower quantities of diesel being purchased. Therefore, how renewables interact with assumed fuel costs needs to be considered.

These are again issues for the TCI Government to consider and decide on. Which options are pursued will depend on the form of core economic regulation adopted (see section 2.3).

6.1.3 Funding arrangements and options

It is not clear that the TCI Government or the electricity companies have made sufficient inquiries into the potential for external funding of renewable initiatives on TCI. This was raised by a number of parties during stakeholder discussions.

As noted in a recent paper published by the International Bank for Reconstruction and Development and World Bank in 2011:[112]

> There are many financial risks and challenges associated with pursuing renewable, interconnection and fossil fuel options. The higher capital investments required for alternative generation when compared to diesel and HFO make financing projects a challenge. Local utilities may have difficulty funding such large investments and some countries may opt for more expensive operating costs to reduce upfront financing. There are also many unknowns when future cash flows and risks associated with high fuel cost assumptions are projected. As a result, utilities may be hesitant to invest in technologies with which they are not familiar, particularly if the new technologies will require utilities to adapt their business model. Private financing, public/private

[112] Gerner and Hansen (2011), op. cit.

partnerships and support from international financial institutions (IFIs) and the international donor community may often be of key importance.

The regulatory measures discussed above (the RAB approach, etc) could address the issue of commitment to capital investment with a long payback horizon. However, there may also be funds available to TCI, which are worth exploring (in terms of funding energy efficiency, distributed renewable generation and utility-scale renewable generation). Box 6.2 provides some examples of potential avenues. It would be for the TCI Government, the Electricity Commissioner and the companies to explore these further.

Box 6.2 Potential funds available for renewable and energy efficiency projects

From the Castalia (2011) report, and discussions with stakeholders, it would appear that a variety of external funds may be available to assist in the promotion of renewable energy on TCI. Such funding has its advantages and disadvantages, the appraisal of which is beyond the scope of this project. The Caribbean is also composed of many jurisdictions with widely variable relations with various multilaterals, and hence what applies elsewhere in the Caribbean may not be available to TCI. There are also links between the various projects and funding arrangements, as will become evident in what follows. It would be for the TCI Government to appraise further what options are open to it, and to identify the most appropriate external sources.

An important recommendation of Castalia (2011) is that the TCI Government should 'ensure that the TCI has full access to international support for sustainable energy measures, in the form of concessional finance, grants, and carbon credits'. The report potential sources for TCI include:[113]

– the UK Government (especially through the Environment Fund for the Overseas Territories);
– the Caribbean Development Bank (CDB), which has recently been piloted in Barbados focusing on energy efficiency in hotel air-conditioning, and, potentially, the Caribbean Hotel Energy Efficiency Action Program (CHENACT), which was established in 2009, with funding from the Inter-American Development Bank (IDB). TCI is not a member of the IDB, but is a member of the CDB;
– the UK Government has carbon abatement targets, and offers payment for compliance with them. TCI The TCI Government would need to undertake further work on carbon abatement options;
– the Global Environment Facility (GEF) and the United Nations Environment Programme (UNEP) each provide grants and concessional loans for renewable energy and energy-efficiency projects that reduce carbon emissions.

Oxera also discussed with stakeholders other potential sources of funding. Some programmes that were noted included the following (whether these also apply in TCI would require further exploration):

– the Caribbean Renewable Energy Development Programme (CREDP), an initiative of the Energy Ministers of the CARICOM region. At present, 13 countries participate. Funding is provided by the United Nations Development Program (UNDP)/GEF, German International Cooperation (GIZ, formerly GTZ), UNDP Target for Resource Assignment from the Core (TRAC), and through contributions from the Organization of the American States (OAS) and regional governments and institutions.[114]

– the Caribbean Renewable Energy Technical Assistance Facility (CRETAF), the funding for which is provided by the GEF. This provides assistance for renewable energy project preparation, by financing grants to those countries participating in the CREDP;

– the Caribbean Renewable Energy Fund (CREF), which provides equity and debt financing to renewable energy projects to countries participating in the CREDP, by co-investing with regional financial institutions. The funding goes to on- and off-grid projects, and a variety of renewable technologies (eg, wind, solar);

– the Energy and Climate Partnership of the Americas (ECPA), which promotes renewable energy in the region, primarily dedicated to regulatory reform. ECPA seeks to foster partnerships across

[113] See Castalia (2011), 'Development of an Energy Conservation Policy and Implementation Strategy for the Turks and Caicos Islands', final report prepared for the Government of the Turks and Caicos Islands, March 31st.
[114] See http://www.caricom.org/jsp/projects/credp.jsp?menu=projects for a further discussion of the CREDP, CRETAF and CREF.

the Americas to achieve low-carbon economic growth and development. Its initiatives can involve the private sector, society and academia, The World Bank, the IDB, the OAS, and the Latin American Energy Organization (OLADE);[115]

– The World Bank, which may also have grants and feasibility funding available;

– the EU Small Island Nation Development programme, which Granada has accessed, for example, in relation to a hybrid wind/diesel project.

Finally, some further initiatives may be as follows:[116]

– the Clean Technology Fund (CTF), with support from multilateral development banks, UN, GEF, United Nations Framework Convention on Climate Change (UNFCCC), and others.

– the Post 2012 Carbon Credit Fund, with support from the European Investment Bank (EIB) and other European public financing institutions.

6.2 Policy: tariff differentials between customer classes

Section 5.3 noted that there is a role for the TCI Government in clarifying its policy towards different charges being made to different customer classes—for example, in relation to social considerations and in promoting tourism. It was also noted in that section that, from a cost-reflectivity perspective, there may be valid reasons why the charges to some types of customer are different to those to other types. For example, larger customers may be less costly to serve on a per-unit basis than residential customers. However, there is a case for requiring the companies to demonstrate to the Electricity Commissioner that such discounts are justified, and, similarly, that any rebalancing of tariffs is also justified.

Interestingly, Fortis TCI has put forward proposals that would *increase* current base tariffs for commercial users, small hotels and large hotels, while keeping residential base rates at *current* levels for residential users. In addition, the South Caicos island public subsidy would be eliminated, with rates equalised to those of Providenciales. Box 6.3 summarises Fortis TCI's plans.

Box 6.3 Fortis TCI proposal to increase and rebalance rates

On August 29th 2011, Fortis TCI proposed under Section 34 of the Ordinance to change its structure of charges as follows:

– residential rates would remain unchanged;
– the remaining base rates to commercial and large hotel customers would face an increase;
– these non-residential customers would also be faced with a declining block structure;
– base rates would be equalised between South Caicos and the main islands;
– the public subsidy to South Caicos would be stopped;
– cost-based rates would be implemented for streetlights;
– the fuel charge would be expanded to incorporate the 'pass-through' of lubricating oil costs.

For example, large hotels are currently charged a flat base rate for all consumption, of $0.17/kWh. Fortis TCI proposes to change this to $[✂]/kWh for consumption up to 100,000 kWh, $[✂]/kWh for the next 100,000 kWh tranche, and $[✂]/kWh for consumption above 200,000 kWh. Residential rates would remain unchanged, at the flat rate of $0.26/kWh.

In rebalancing its rates across user types, Fortis TCI notes these charges would be more cost-reflective, even though a detailed examination of the costs-to-serve analysis for each user type had not been undertaken:

> a full detailed cost allocation model is not considered necessary…Even without [this], certain rate-related observations are possible. In particular, the range of rate levels

[115] See http://ecpamericas.org/

[116] See, for example, Castalia (2010), 'Panel 1: The Big Picture Opportunities and Who will Pay for Them', published presentation on renewable energy funding options in Barbados, October.

> offered by Fortis TCI should be narrower. Fortis TCI does not have a significant variation in the cost to serve customers since all energy is produced by the same fuel and generator type regardless of time of day or base-load versus peaking capacity needs. Due to this practically homogonous nature of the generating facilities, the cost of power production is not significantly different during on-peak versus off-peak time periods. Conceptually, a narrow range of rates is also justified since the system average load factor is relatively high, indicating that all customer classes are likely contributing significantly to the peak demand…These factors indicate that both fixed and variable costs should be allocated fairly uniformly to all rate classes within Fortis TCI. Therefore, the range of rate levels among all of Fortis TCI’s customer classes should be much narrower than the range exhibited by the existing rates.

As regards the rationale for increasing the revenue raised from users overall, Fortis TCI claims that it is not, at present, earning a reasonable margin on profit. Going forward, the business predicts that returns will fall even further up to 2015 under the existing base rates and fuel cost adjustment mechanism, principally due to:

– increases in lubricating oil costs, which cannot currently be passed through via the fuel adjustment mechanism;
– forecast future demand growth (of up to [✂]%);
– forecast inflation (of [✂]%);
– forecast capital investment by the business. (The ‘rate base is projected to increase by approximately $[✂]m over the five-year forecast period. This is a significant increase, but represents typical utility investments to accommodate growth in demand for [electricity]’.)

It is not clear what target profit margin Fortis TCI has included in its analysis, although it is noted that the rates increase is ‘modest’, and that the return incorporated is far below the 17.5% ‘allowed within the licence’, or to recover ‘cumulative shortfall’ historically. For example, Fortis TCI notes that ‘base rates need to be increased by an average of [✂]% in order to recover operational expenses and the allowed return on the rate base. It should be noted that an even greater rate increase would be required to cause the cumulative shortfall balance to decline’. However, Fortis TCI does not set out explicitly what rate of return has been assumed in its analysis under revised rates.

Source: Utility Consulting Services (2011), ‘Fortis TCI 2011 Electricity Rate Variation Application’, letter from Doug Handley to Eddinton Powell, August 26th.

Without commenting definitively on the rate-case submission, Oxera notes that Fortis TCI is probably correct in its perception that charges are currently not cost-reflective, and that there needs to be some form of rebalancing of charges between larger and smaller users. This may also encourage greater energy efficiency by larger users.

Furthermore, the declining block structure should remove any perverse incentive for a user to consume more electricity in order to pass the current discount thresholds. The ending of the South Caicos public subsidy will be of benefit to the TCI Government, although the average Providenciales customer will pay slightly more as a result of this and the rebalancing.

However, it would be useful for Fortis TCI to gain a better understanding of the costs to serve different customer groups, as this will help it determine whether further rebalancing might be required in future.

Oxera also notes that Fortis TCI argues that it has not been able to earn a return of 17.5%, to which it believes it is entitled, and that the business claims that it is entitled to a shortfall (including interest). As discussed in section 5.2 (and section 2.3 before this), the status of these issues is the source of continued disagreement between the TCI Government and Fortis TCI.

From a purely economic perspective, however, it is not clear that revenues from users *overall* should increase. This highlights one of the problems with the current regulation in relation to transparency and justification of tariffs. In particular, no evidence is presented on:

- **the WACC that would be appropriate to an efficient utility facing this situation**. Fortis TCI states that 'the Licence specifies the allowed rate of return' and that, in the absence of a rate rise, 'the projected rates of return… are well below reasonable rates of return for utility investments with risk profiles comparable to Fortis TCI and… a fraction of the allowed rate of return specified in the Licence';[117]

- **the current levels of efficiency (and hence unit costs)**. No evidence is provided on whether the company is operating at a reasonable level of OPEX efficiency or whether its recent investment activity (and hence its existing asset base, on which it currently calculates a return) has been efficient;

- **the future levels of efficiency that could be achieved**. Fortis TCI does not explicitly consider within its planned investment programme (and hence expansion in the asset base), or whether future operating costs, are efficient. The investment programme as part of the proposals is referred to simply as an 'investment in rate base by 2015';

- **the role of demand growth is unclear**. Part of the reason for the investment envisaged by Fortis TCI, and the rationale for its proposed base rate increases for most customer classes, is a picking-up of demand growth in future. While some of the investment proposed is to improve the island connectivity of the transmission and distribution system, demand growth is also emphasised as a driver. It is not clear that rates overall would need to increase to meet such a demand increase as units sold increases—in particular, if there are rate increases for these customers through the rebalancing exercise.

For the above four reasons, under the existing rate-base system—or, indeed, any future regime of tariff-setting—it is not clear that the *economic* case has been made that rates overall should rise. The issue that historical underperformance could be explained (at least in part) by inefficiency cannot be ruled out. Furthermore, the future investment programme of the business has not been set out adequately, and has not been subject to sufficient challenge.

6.3 Core regulation: incremental versus fundamental reform

As noted in section 5.1, the core regulatory approach should seek to promote the customer interest, encourage efficiency, and allow the utilities to finance their functions. Section 5.3 showed that this will involve a choice between adopting incremental changes to the existing rate-base approach and adopting more fundamental changes.

More fundamental reform could involve introducing price cap regulation, potentially supported by a building-block approach to determining the revenue allowance within the price control. If pursued, this option would require changes to the existing Ordinance, regulations, and licences, and final clarification on the status of the takeover agreements (in particular, the status of the 15% and 17.5% target return figures).

Building on section 5.3, the changes that could be adopted on TCI are further explored in this section. It should be emphasised that these are options for reform, rather than recommendations. It is also acknowledged that the TCI Government may, on further examination, prefer to adopt some aspects of these options but not others.

This section is structured as follows.

- There is first a discussion of how some of the current problems with the existing rate-base regime could be addressed through incremental changes to the current approach.

[117] Utility Consulting Services (2011), 'Fortis TCI 2011 Electricity Rate Variation Application', letter from Doug Handley to Eddinton Powell, August 26th, p. 6.

- More fundamental reform could include the introduction of price cap regulation. The general experience of this in the Caribbean is therefore discussed.

- A step-by-step guide is provided on how price cap regulation, if introduced, could be implemented in TCI.

- A step-by-step guide is then also provided on how a building-block approach could be used alongside a system of price cap regulation in TCI.

6.3.1 Incremental changes: addressing the issues under the current regime in TCI

Section 5.3 highlighted that the existing regime has some benefits in terms of TCI securing a high degree of reliability. Information is provided on an annual basis on key financial and operational issues for monitoring purposes. Radical change would also bring about costs.

Rather than more fundamental reform, some measures could be undertaken under the current system of regulation and existing legislation, as follows.

- **Base rates and fuel**—because the base rate assumes fuel costs that are out of date ($0.90 or $1.00/gallon), this could be updated through changes to tariff regulations (under Section 33), to provide for a best estimate of fuel costs at the start of each financial year. This would provide a more transparent indication to consumers about the costs of electricity that they are likely to face over the coming year, which will help them to budget better. The base rate could also include an up-to-date assumption on fuel-burn efficiency (see below).

- **Fuel cost adjustment and efficiency**—with the above in place, the fuel cost adjustment would then represent a lower proportion of bills. The adjustment itself could also factor in a more realistic and up-to-date assumption on fuel-burn efficiency. The present assumption of 0.08 is out of date, and has the effect of financially rewarding the companies when fuel costs are high, but potentially penalising them when fuel costs are low. This could be undertaken through changes to regulations (under Section 33). The companies could also do more to publish, in advance, what future bills (through potential movements in the fuel cost adjustment) are likely to be in the coming months. This would enable residential consumers, in particular, to budget better.

- **Investment assessment**—there could be a voluntary arrangement in which the Electricity Commissioner is permitted to review, on merit, the proactive investment plans of the company ex ante, and to provide an opinion to the companies and the Governor on the prudence or otherwise of the plans before large investment is committed. At the same time, this should not hinder restoration of service following hurricanes or other adverse weather events. This could, in turn, be considered as evidence at any future rate review request.

- **Operating and performance efficiency**—the companies could voluntarily agree to share evidence of their initiatives to improve efficiency with the Commissioner, including internal benchmarking exercises, business case scenarios, and benchmarking undertaken through CARILEC.

- **Customer engagement**—the companies could sign up to a voluntary arrangement, stating that they would undertake engagement with their customers on their investment plans before pursuing these.

- **Service performance**—the companies could also sign up to developing customer-facing service metrics, and publishing these on a regular basis. This would capture the broader customer experience (eg, complaints, dealing with complaints), as opposed to just operational metrics (interruptions) on which the companies perform well.

However, as noted in section 5.3, such changes may not radically alter the incentives present under the existing regime with respect to efficient levels of investment or OPEX, for example. Many of these changes would rely on voluntary initiatives, which the companies may or may not sign up to.

A more fundamental alternative would be to introduce some form of price cap regulation. Section 5.3 explained that this typically involves introducing an RPI – X fixed-price contract, which the utility has incentives to outperform. Additional mechanisms can be introduced to deal with uncontrollable costs (risk-reducing measures), and other mechanisms can be introduced to provide incentives for a good quality of service (reward-increasing measures).

The way in which price cap regulation would be applied in TCI cannot mirror the detail and full host of information requirements often observed in larger jurisdictions implementing this regime (such as the UK, and certain US states); rather, the approach would need to be proportionate to the situation faced on TCI, in terms of the scope of regulation, the information requirements, and who does what.

6.3.2 Price cap regulation: Lessons from the Caribbean experience

From a practical perspective, it is first useful to explore the experience of price cap regulation elsewhere in the Caribbean. In this regard, it is of note that CARILEC supports price cap regulation over cost of service (or rate base) regulation:

> The presence of a stable regulatory framework is important to assure a proper balance between consumer demand for low prices and investors' need for a reasonable return. Rate setting should rather be implemented by incentive-based regulation using the so-called price cap methodology than by applying the methodology of rate of return regulation which may lead to weak efficiency incentives and over-capitalization[118]

Furthermore, CARILEC has noted:

> The price cap approach is generally favoured by regulators as it promotes higher productivity in a manner similar to the incentives experienced under competition…In order for price cap systems to be effective it is important that the regulated utility is provided a fair chance to actually retain the productivity improvements that it is able to achieve…It is also important to realize that the unlinking of actual costs and prices introduces risks for the utility. These risks will need to be reflected in the allowance for the costs of capital faced by the utility.[119]

An important caveat raised by CARILEC is that, since fuel costs depend on fuel prices, which are outside the utility's control, the price cap method is not applicable to fuel charges.

There is increasing use of price caps across the Caribbean. While cost of service regimes are common, price caps are used in the Bahamas (in the case of Grand Bahama Power Company), Dutch Windward Islands (GEBE), Grenada (GRENLEC) and Jamaica (Jamaica Public Service Co. Ltd). A form of incentive regulation (cap and collar) is also used in Belize (Belize Electricity Limited).[120]

Arguably, however, price cap regulation needs the institutional measures to support it, to create the right incentives, and to engender investor confidence. Belize Electricity Limited, which is subject to a hybrid form of incentive regulation, recently encountered funding difficulties, and was renationalised. (Fortis previously owned 70% of the entity.) The

[118] CARILEC (2008), 'Position Paper on Energy Policy', January, p. 22.

[119] CARILEC (2010), 'Position Paper on Regulation and Renewable Energy: Minimization of Barriers and Provision of Incentives for Renewable Energy Technologies and Alternative Fuels', p. 13.

[120] See CARILEC (2010), 'Benchmark Study of Caribbean Utilities: Sixth Update – Year 2009', draft report, September.

Chamber of Commerce on the island regards the move as being politically motivated, and somewhat damaging to investor confidence.[121]

That said, such interference can occur under any system of regulation. Bahamas Electricity Corporation (BEC) is state-owned, and subject to a cost of service regime, unlike its counterpart on the Bahamas, GBPC (which is 100% privately owned, and subject to price cap regulation). Over the past few years, BEC has been loss-making, and there have been blackouts due to inadequate maintenance. While the company has faced criticism, a number of commentators have stated that the fundamental problem is the reduction in rates that have been introduced for political reasons. When coupled with inadequate allowance within rates for import taxes on fuel, this has led to the utility being unable to finance its functions.[122]

The case of Grenada (see Box 6.4[123]) illustrates where a price cap regime seems to have been successfully introduced, in both form and (to an extent) process. This also demonstrates how the fuel factor adjustment adopted in Grenada differs to that in TCI, and how a hurricane insurance fund operates (see section 6.7 below). It should be noted, however, that the regime in Grenada does not appear to rely explicitly on a building-block approach. In addition, the price cap has remained in perpetuity. Grenada is also a larger jurisdiction than TCI in terms of customer numbers (see section 3).

Box 6.4 The Grenada experience of price cap regulation

The parent company of TCU, WRB, also owns and operates GRENLEC in Grenada, a member of the Organisation of Eastern Caribbean States (OECS).[124] GRENLEC is the sole provider of electricity to Grenada, which is made up of the islands of Grenada, Carriacou and Petite Martinique. GRENLEC was privatised in 1994, with the government retaining 10%, selling 50% of GRENLEC shares to WRB, and the remainder to GRENLEC employees and Grenadian and Caribbean nationals.[125]

Under the Electricity Act, electricity rates in Grenada are regulated through a price cap regime, based on the consumer price index (CPI). According to discussions with TCU, a two-part mechanism was established at privatisation:

– a non-fuel rate (base tariff): a price cap mechanism was established at CPI – 2 for non-fuel costs;
– a fuel surcharge mechanism: this captured all fuel costs, and an adjustment mechanism to deal with fuel cost outturns.

The legislation made the above price cap (and fuel surcharge/adjustment) formulaic and automatic. Even though the legislation allowed for the appointment of a utility regulator to the Public Utilities Commission, the government has not appointed one in practice.

In practice, the same CPI – 2 price cap has been maintained, in its original form, for 16 years. According to WRB, this has worked for the company and its customers. The clear and automated nature of the process has, to a large extent, been self-governing.

The company has highlighted that the base tariff established, coupled with demand growth and efficiencies, has led to a reasonable profit.

– This was assisted by ten years of demand growth that exceeded 7% per year (although this has slowed in the current economic climate to 3–4% per year). This meant that revenue increased in the face of expenses and staffing costs remaining fairly fixed.
– The company also increased its efficiency in administration costs and elsewhere in its

[121] See, for example, commentary on these issues at: http://caricomnewsnetwork.com/index.php?option=com_content&view=article&id=4095:belize-opposition-and-private-sector-worried-over-nationalization-of-electricity-company&catid=37:caribbean-business&Itemid=396

[122] See for example, commentary on these issues at: http://www.thenassauguardian.com/index.php?option=com_content&view=article&id=12158&catid=43:national-review&Itemid=37

[123] The discussion in this box is based on discussions held with TCU, unless otherwise specified.

[124] The OECS covers six states: Antigua and Barbuda, Dominica, Grenada, St Kitts and Nevis, St Lucia, and St Vincent & the Grenadines.

[125] Source: GRENLEC website, accessed October 2011.

operations.

As regards the fuel surcharge mechanism, the fuel efficiency rate assumption is fixed at a given level and, if the business outperforms the assumed fuel-burn rate, it retains 90% of this and passes on 10% of the benefit to consumers. This outperformance benefit has helped to incentivise and finance the replacement of the (previously high-speed) generation plant with modern and more fuel-efficient medium-speed diesel units.

GRENLEC notes that, over the last 15 years, there has been an increase of 7.18% in the non-fuel component of electricity rate, compared with inflation of over 40%. There has been some political pressure on tariffs, however. In 2010, at the request of the government, GRENLEC agreed to maintain the non-fuel rate, even though the law provided for an increase. In February 2011, GRENLEC reduced the non-fuel rate by 0.96%, providing some reprieve for customers.[126]

With the decline in demand growth, and with many efficiencies now having been made, the business is getting close to the point where a ‘minus X’ factor of 2 may be somewhat more challenging to achieve.

The fuel surcharge mechanism currently assumes that diesel is being consumed to generate electricity. If renewables are to become more prevalent in future, the public may question paying a fuel surcharge if a lower percentage of fuel actually comes from diesel units. The fuel surcharge mechanism may therefore need to change in future, to share the benefits of savings in fuel costs more effectively. However, in deciding on this sharing, there must still be an incentive for the business to invest in renewables in the first instance.

Provisions exist to deal with exogenous shocks to costs, but the need to trigger these has not arisen. In addition, there is a separate provision for hurricanes. The utility pays into a ring-fenced tax-deductible hurricane fund each year. This is a non-distributable equity buffer, to cover the reinstatement of the network in the event that it is severely damaged by a hurricane. When this fund becomes large enough, GRENLEC stops paying into it. WRB noted that the alternative of private insurance would not be available (at least not at good rates). With this mechanism in place, GRENLEC managed to rebuild the entirety of its distribution system after Hurricane Ivan. WRB has noted that, were such a mechanism present on TCI, TCU would not have sought a rate review in 2011. Hurricane funding arrangements are discussed further in section 6.6 below.

Source: Discussions with TCU.

6.3.3 More fundamental reforms: implementation of price cap regulation in TCI?

Section 5.3 discussed the rationale for adopting a price cap approach in TCI, and what this involves in general. A step-by-step guide is provided below on how this could be introduced in TCI, if this route were to be pursued.

As regards implementation, it is suggested that the first price control period ‘N’ could be between 3 and 5 years, in order to test the system and bed it down.

The benefits of different control periods will also depend on whether a multi-sector regulator approach is to be adopted, and whether a price control approach is to be adopted in other sectors (see section 6.5). In this vein, reviews might be staggered across the sectors to make the best ongoing use of regulatory resources.

As regards the regulatory regime itself, the regime could work along the following lines:

– **Powers of the regulator**—the regulator would have ultimate power ex ante to set prices, subject to the price cap and fuel cost mechanisms to be specified in regulations. At price reviews, the regulator can discuss with companies the most appropriate form of these controls. However, the final decision would rest with the regulator.

– **Length of control**—the first price control would be for N years (as noted, most likely to be between 3 and 5 years, to bed the system down).

[126] See ‘GRENLEC Welcomes the Establishment of an OECS Regulatory Authority for the Energy Sector’, press release circulated to Caribbean journals in July 2011.

- **Base costs (T1)**—fuel costs for generation purposes would be separated out from other costs altogether. The remaining costs would be (mainly) controllable costs, which would be subject to a fixed price cap for each of the N years of the control, using an RPI – X methodology. This would also include a best estimate of taxes and duties to which the electricity company would be subject to over the next N years (eg, carbon tax).

- **Fuel costs base (T2)**—an additional component of charges would be the fuel cost base, included in each of the N years of this cap as a best estimate of fuel costs for the year concerned. This may also be reviewed from year to year once prices are set.

- **Fuel cost adjustment (T3)—**for the reasons discussed in section 3, it would be accepted that fuel costs are largely uncontrollable, and that there is little the companies can do to mitigate these costs in the short to medium term. As such, for monthly fuel cost outturns that go beyond those assumed in T2 (above), the company would be permitted to increase prices, and for monthly fuel cost outturns below those assumed in T2, the company would be required to lower prices.

  - This would work in a similar way to the current fuel adjustment mechanism, but would be subject to an updated fuel efficiency factor.
  - In addition, under their licence the companies would be subject to an efficient purchasing obligation.
  - The companies would be permitted to smooth fuel cost increases, rather than applying adjustments in every month.

- **Quality of service**—the regulator would develop, with the companies, customer-facing metrics of quality of service. At present, the metrics reported are mainly operational. It would be for the regulator to determine the balance to be struck in terms of:

  - publishing data on the quality of service of the companies;
  - rewarding or penalising the companies in each year of the price control for good or poor service;
  - introducing individual customer-specific compensation arrangements.

A potential sticking point in TCI is finding an appropriate metric to use for RPI to provide cost pass-through for inflation, as accurate statistics over recent years have not been collated. Any such metric is likely to need to be TCI-wide, rather than having a separate index for Fortis TCI and TCU. Which metric to use would be open for discussion. Double-counting of fuel cost inflation (for example, within T2) would need to be avoided, given that the fuel costs are themselves a major component of RPI.

6.3.4 Implementation of a building block approach in TCI?

Section 5.3 discussed how a price cap approach can be complemented using a building-block approach. A step-by-step guide is provided below on how this could be introduced in TCI, if this route were to be pursued.

In the interests of proportionality, the building-block exercise would need to focus on the most pertinent tasks, and should divide responsibilities between the regulator and the companies according to which of them is best placed to undertake the task concerned.[127] Below is one model that could be pursued.

- **Business planning**—the companies would be required to prepare business plans, setting out their strategy, and focusing on the outputs they wish to obtain and their longer- and shorter-term projections of CAPEX (and OPEX).

[127] Other price cap approaches can be delinked from cost projections and allow for increases in tariffs net of an assumed efficiency per year. Forms of price regulation delinked from costs are, however, not used in general, and the cost-linked or building-block approach is the predominant form adopted by regulators.

  - It would be for the companies to demonstrate to the regulator that the CAPEX they propose is required, that their proposals are efficient, and that these offer value for money to customers. It is not for the regulator to assume that investment is prudent unless it can be proven otherwise, given the information and resources asymmetry present.
  - There would be a requirement for the companies to undertake customer engagement, to find out what outputs their customers (and other stakeholders) want and are prepared to pay for (see section 6.6 below).
  - The regulator would have the power to question elements of the plan on which insufficient evidence has been provided.
- **Efficiency analysis**—given the small-island context, the companies are better placed than the regulator to analyse their efficiency and future prospects for efficiency. Evidence that the companies might submit could include:
  - evidence as revealed by the annual (top-down) CARILEC benchmarking survey;
  - internal benchmarking analysis on KPIs;
  - a requirement placed on the companies to have an independent expert visit the plant and operations of the business, to verify (as a bottom-up process) whether the company concerned is efficient. This should be possible in a small-island jurisdiction.
- **Cost of capital**—as part of their business plans, the companies would need to submit evidence on what they think is an appropriate cost of capital. However, it would ultimately be for the regulator to decide on the appropriate cost of capital, taking account of the available evidence.
- **Regulatory asset base**—the regulator and the companies would seek to agree on an appropriate opening asset base for the first control period. However, it would ultimately be for the regulator to decide on the appropriate opening RAB, taking account of the available evidence.
- **Depreciation**—as part of their business plans, the companies would need to submit evidence on what they think is an appropriate approach to depreciation. However, it would again ultimately be for the regulator to decide on this, based on the evidence.

6.4 Institutions: regulatory style and powers

If ex ante price cap regulation were adopted, in the way set out above, this would require changes to the Ordinance, regulations, licences, and final legal clarity on issues in the takeover agreements.

As noted in section 5.3, to enable price cap regulation to work, it would be important to ensure that the regulator is sufficiently independent from the government. This would require changes to the Ordinance. However, full independence may be difficult to achieve in a small-island setting.

As also noted in section 5.3, were price cap regulation and an independent regulator to be introduced in TCI, the emphasis would need to be on *getting right the aspects that really matter*. Yarrow and Decker (2010) refer to this, in a small-island context, as being about ‘doing a limited number of biggish things well’, rather than seeking to cover many issues, in detail: [128]

> We conclude that regulation can work in a small economy, but that, precisely because of its size, issues such as the *scope* and *proportionality* of regulatory activity are of critical importance.

In the Caribbean, CARILEC (2010) notes how formal regulatory bodies are being set up in a variety of countries, including Barbados, Belize, Cayman, Dominica, Jamaica, and Trinidad & Tobago.[129] While CARILEC supports the adoption of independent regulators, it similarly notes that the focus and costs of regulation need to be tailored to the specific circumstances of the country concerned:[130]

> …pro-active cooperation of the electric utilities with establishing an independent and capable energy regulator is a prerequisite for achieving an appropriate regulatory framework and regulatory practices. The Regulation model should be a model tailored to the situation of the Caribbean island states… Tailoring the regulation model to the situation of small Island States should also include tailoring of the cost of Regulation… [Also] the presence of independent regulatory institutions is of utmost importance. An effective pricing policy should ideally be disconnected from the political process, at least in the short run. This can only be achieved through the establishment of independent energy regulators.

Turning to TCI specifically, to undertake price cap regulation, the independent regulator would probably need to have powers to:

– assess ex ante the investment and operational plans of the businesses;
– determine ex ante prices (according to the form of regulation adopted—in practice, T1 and T2, and the components of T3);
– demand information from the companies for the purposes of undertaking a price review, and between price reviews (beyond that currently permitted by the Ordinance in Sections 33, 34, 43 and 44, and other relevant sections);
– monitor the fuel cost-pass-through regime (and, in practice, both T2 and T3);
– monitor whether companies are meeting their licence obligations, and if not, take any necessary action.

The regulatory style that could be employed in TCI, and the independence and various powers of the regulator, are explored next. Resourcing options are discussed further in section 6.5. The emphasis throughout is on introducing *proportionate* regulation.

6.4.1 Regulatory style

Historically, the companies have had an information and resourcing advantage over the regulator. In this regard, the regulator could have more powers to demand information from the companies, and to examine proposals for investment. However, in the specific TCI context, the following should be borne in mind:

– Due to the resourcing constraints, as noted the regime would need to be *proportionate*. The new regulatory body would need to adopt a regulatory style that involves doing a few important things well.

– The approach followed would need to recognise that incentives are multi-faceted. It is of little benefit to cover all issues in detail. Complex regulation would be difficult to resource, and could damage (process) incentives on TCI.

[128] Yarrow, G. and Decker, C. (2010), ‘Review of Guernsey’s utility regulatory regime’, Regulatory Policy Institute, A report for Commerce and Employment.
[129] CARILEC (2010), ‘Position Paper on Regulation and Renewable Energy: Minimization of Barriers and Provision of Incentives for Renewable Energy Technologies and Alternative Fuels’, March, p. 8.
[130] CARILEC (2008), ‘Position Paper on Energy Policy’, January, p. 21.

- The approach in dealing with the companies would need to avoid being completely adversarial. Significant issues (eg, future efficiency, future investments) would require cooperation and an open dialogue with the companies.

- The regulator would undertake certain analyses as part of a revised regulatory framework where it is best able to do so (eg, the overall framework, cost of capital issues).

- The companies would, where possible, have incentives to undertake robust analysis on key issues, such as efficiency and investment, rather than the regulator necessarily undertaking the analysis. The regulator could then scrutinise this analysis, and approve or require further work, as necessary

As regards information currently provided, this is mainly in the context of the fuel cost adjustment data and annual schedules (and audited financial statements) required under the Ordinance. The regulator might instead have broader powers, under a revised regime, to demand whatever information that is needed for undertaking a rate review (whether under a revised rate review system or a new system of price caps).

As noted in section 5.3, there should be an emphasis on regulatory transparency. The following would be particularly important under a new system of price caps.

- **Clarity on the process**—the regulator would need to make clear from the outset the timeline for making decisions, when it plans to publish consultations and decisions, and any other relevant milestones.

- **Clarity on the methodology**—the regulator would need to consult on and make clear, at a reasonably early stage in the process, the constituent components of its approach (eg, the form of any price cap, the building-block approach, the calculation of the return on capital). It would also need to make clear upfront what the process will be, once prices are set, for adjusting tariffs to deal with uncontrollable events.

- **Clarity on decisions**—in publishing its decision document on allowable prices, the regulator would need to illustrate how its methodology was implemented, and how key decisions or judgements were made.

6.4.2 Regulatory powers, duties and information requirements

To support a price cap framework, as noted the regulator would need to be sufficiently independent of the TCI Government. There would need to be changes to the existing Ordinance, regulations, and licensing arrangements. Key aspects that could be introduced are set out below (note that this is not an exhaustive list).

- **Independence**—the Ordinance would need to be revised to establish the regulator as a separate independent body.

- **Duties of the regulator**—the Ordinance would need to *enable* RPI – X regulation and a revised fuel cost-pass-through mechanism, but would not be too prescriptive on precisely how this should be undertaken. Sections 32, 33 and 34 of the current Ordinance would need to be replaced. The processes described under Sections 33 and 34 would be removed, as they are over-prescriptive for an independent regulator under an RPI – X regime. Section 32 could then be replaced with wording more suited to independent regulation, such as:

  - the regulator will have the power ex ante to set prices, under regulations, in a way that is consistent with its duties;

  - the regulator's will have a duty to protect consumers; to enable the companies to finance their functions (including by earning a reasonable return on capital); and to promote efficiency;

  - the regulator will also have a duty to encourage a sustainable electricity sector; to have regard to affordability issues for vulnerable groups; and to encourage forms of third-party participation in electricity generation where this is feasible and cost-effective;

  - the regulator will have regard to government policy on renewable energy and conservation;

  - decisions will need to be based on objective evidence, wherever possible, and the decisions of the regulator should be justified and reasonable.

- **Price-setting (or tariff-setting)—**in setting prices (or tariffs):

  - the regulator would be required to determine prices, by setting out regulations, according to an RPI – X formula, accompanied by a fuel cost adjustment;

  - determining the revenue requirement in each year *may* include the regulator assessing and setting an appropriate level of OPEX and CAPEX, asset base, cost of capital, depreciation, and other parameters as relevant;

  - such price reviews should take place every N years, where N is determined through regulations. In the first instance, N could be around 3–5 years (see section 6.3);

  - once the regulations are set through the completion of a price review, the regulator would be bound by these for the period N, as would companies as part of their licence conditions. The prices set would not be revisited, except in (exceptional) circumstances as prescribed in the regulations;

  - companies would have the right to appeal against the regulator's price determination (see below).

- **Information powers of the regulator**—the regulator would have the power to demand information from the companies as is reasonable and proportionate to fulfilling its functions. For example, it could demand information for the purposes of:

  - undertaking a price review (a requirement that would also be set out in the companies' licences, analogous to the powers of an Inquirer under Sector 34 of the Ordinance);
  - monitoring performance between price reviews (a requirement that would also be set out in the companies' licences)—building on the provisions for annual information provision under Section 43 of the Ordinance.

- **Regulations**—the regulations would then specify in more detail the mechanism through which prices would be set (at a level of detail not contained in the Ordinance). This would include the following:

  - N: the choice of control period N (for example, 3–5 years);
  - T1: for costs other than fuel costs used for generation, the level of prices for each of the N years, as per an RPI – X formula;
  - T2: baseline fuel costs allowed in each of the N years for fuel costs (not linked to RPI);
  - T3: a fuel cost adjustment mechanism for the N years of the control period (not linked to RPI);

  - charges being set for different customer classes in a way that is consistent with the regulator's duties, for each of the N years, forecast by the regulator over the N years to recover the revenue requirement;
  - if, during the control period, companies seek to rebalance charges between customer classes, provision within regulations might be made for this (subject to rules on the recovery of the revenue allowance, adjusted for out-turn customer growth). Care would be required in designing any such provisions;
  - the regulations may contain adjustments for quality of service in each year;
  - the regulations are subject to the operation of any potential additional hurricane funding arrangements.

- **Licensing—**under their licences the companies would need to:

  - comply with the **pricing methodology** as set out in the Ordinance and under regulations;

  - ensure that the regulated business is **ring-fenced** such that the activities of the parent business or its associates do not adversely affect consumers of the regulated business (this includes ring-fencing of information, and financial ring-fencing);

  - **provide information** as required by the regulator under the Ordinance and through the regulations;

  - **comply** with licence provisions—non-compliance would lead to sanctions (see below);

  - be under an **economic purchasing obligation**;

  - be under a **non-discrimination obligation** not to discriminate unduly between different types of customer.

- **Appeals**—the companies would have the right to appeal the regulatory price control decision (see below).

In terms of information provision, some of this is already provided to the regulator, some is collated but not currently asked for, and some would need to be collated.

- **Information currently provided to the regulator**: annual regulatory tariff submissions, annual accounts, fuel cost information, presentations on performance and investment plans, approach to renewables, information provided to date at rate reviews.

- **Information currently compiled (in this case by Fortis TCI) but not asked for by the regulator**: business plans, demand forecasts, benchmarking activities (KPIs), investment cases, service-level performance and targets, detailed management accounts by cost centre.

- **Further information that could be collated and provided**—more evidence on benchmarking, demand forecasts, investment cases, service levels, engagement with stakeholders, etc.

Crucially, the above provisions would require legal clarity on the status of the takeover arrangements, not least including:

- the ability of the regulator to determine the appropriate and reasonable level of the WACC;

– clarity on who is responsible for paying for additional investment when hurricanes occur (see section 6.7 below).

There may also need to be a revision to the Ordinance in terms of what happens in the event of a failure by an electricity business. At present, Section 45(2) of the Ordinance grants the Governor, in the event of a major failure in performance by a supplier, the power to direct the Electricity Commissioner ('or such other person as may be specified') to take over management of that supplier. This would be invoked where, in the event of such a failure, there would be harm to consumers over a longer period than 'might be reasonably be expected', which cannot otherwise be remedied in good time.

Under Section 7 of the Ordinance, the Governor can also revoke a licence in certain instances, including where a supplier fails to provide consumers with a regular and efficient supply of electricity, and on safety grounds. A supplier may appeal against such a ruling to the Supreme Court (under Section 8 of the Ordinance). Where a licence is revoked, Section 47 states that the Governor may order the business to be nationalised.

Together, these two provisions form a kind of 'special administration' regime for the TCI electricity sector. Some form of safety net is likely to need to remain in place, to cover the unlikely (but severe) scenario in which an electricity supplier is materially unable to continue to provide its service (or unable to rectify its poor performance).

A question going forward, however, is whether it would still be the Governor determining that the supplier has materially not performed. Under more independent regulation, it would be for the Commissioner to raise the issue of poor performance in the first instance. There is also an open question about who should have the ultimate power to revoke a licence under independent regulation (this could be the Commissioner), and the appeals route to be followed.

As a step *before* very serious failings, however, it is perhaps desirable that the new regulator has the power to demand rectification of problems, and information and continual updates in the event of less serious breaches of licence conditions. This could prevent any situation from escalating, and would provide any failing company with the opportunity and incentive to sort out issues before they reach a critical stage. This would involve a change to the existing Ordinance.

Licence renewal is also a controversial issue. Fortis TCI has expressed concerns in this area:

> There should be a legitimate expectation that a licence will be renewed at the expiry of its term if the licensee has operated in accordance with the law and its licence…A licensee whose licence is not renewed shall be compensated fully by the Government for the value of its assets, as established in proceedings before the International Court of Arbitration or another Court of Law acceptable to the licensee.[131]

This is open for discussion as part of a revised regulatory framework. However, it is a legal (rather than an economic) issue, and is not discussed further here.

There would also still need to be an appeals process. As noted, as part of the current appeals process, the appointed Inquirer could have the final say on prices. The Governor would be able to provide its views to the Inquirer as part of the process, but would be prohibited from otherwise influencing the process. Alternatives are that, following the decision of the appointed Inquirer:

– the Governor would have the final say, but, in the event that the findings of the Inquirer were not taken on board, would need to set out its reasons in some detail;

[131] Fortis TCI (2011), 'General regulatory principles', August, p. 3.

– the Commissioner would have the final say, but in the event that the findings of the Inquirer were not taken on board, would need to set out its reasons in some detail;
– the matter could go to an arbitration panel, convened specifically for the task;
– the matter could go to a high court (although such a body may not have the economic expertise).

Each of these options has advantages and disadvantages, and would require changes to the existing Ordinance.

6.5 Institutions: resourcing strategies

As noted, regulation is typically more challenging on small-island economies due to the fixed costs involved relative to the size of population served, and the potential lack of human resources. In this regard, in setting up an independent regulatory body, various strategies are available, including:

– introducing a stand-alone independent regulator for electricity services;
– introducing a multi-sector regulator across various TCI services;
– engendering closer corporation with other Caribbean jurisdictions;
– accessing available funds from The World Bank and other institutions;
– using external experts for key phases of work (via outsourcing).

Introducing a stand-alone electricity regulator, if this includes a full complement of full-time regulatory resources, may not be viable in TCI. For example, having even two individuals within this entity might not be cost-effective.

One approach to mitigate this problem could be to adopt a multi-sector regulator. This would enable resources to be spread over multiple roles, with the benefit of lower costs per customer served, and the ability to apply expertise gained in one sector to another. If reviews of the different sectors (say, under a price cap regime) are staggered, this would also ensure resource utilisation across the sectors at the time that rates are set.

The resources required may also depend on the regulatory style adopted and whether there is a persistent regulatory presence, or one that is convened only when tariffs need to be set. Outsourcing key phases of work to external experts may be a strategy in the latter case.

A draft report by the TCI Ministry of Housing Works and Utilities, reviewed by Oxera, proposes introducing a multi-sector regulator:[132]

> In the report on the review of the Ministry of Housing Works and Utilities it is proposed that the current separation of regulatory and statutory bodies overseeing the individual parts of the utilities sector is not viable given the size of the market and geographical demographics…

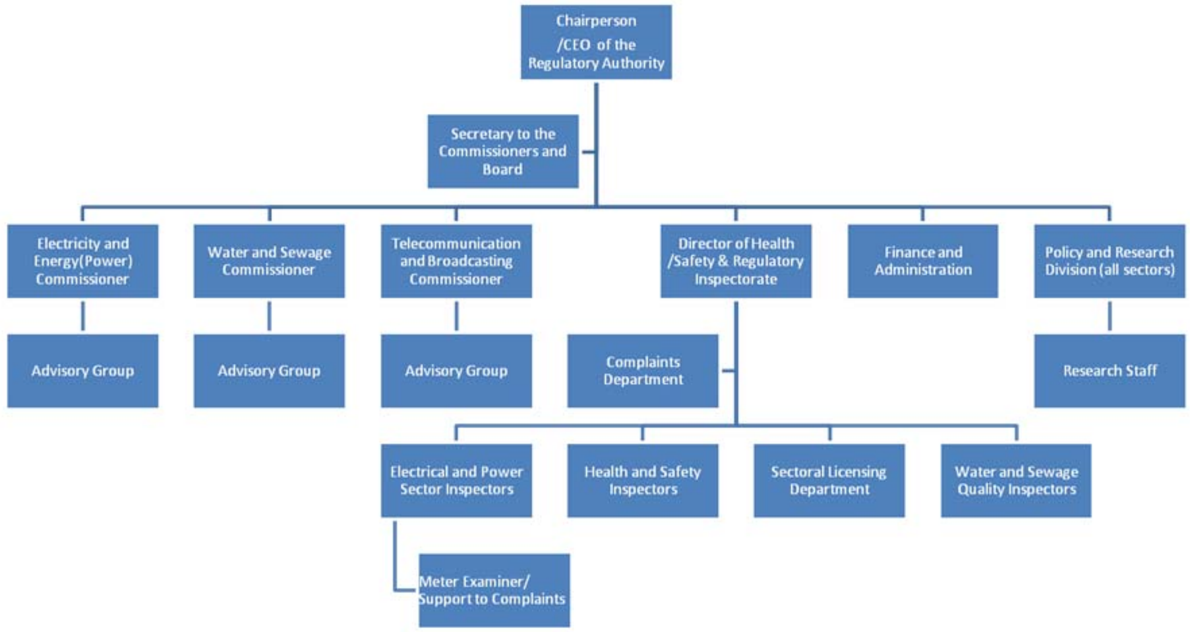
At this stage, the report notes:

> We are of the opinion that to fully support the regulation of the electricity sector the Commissioner's Office will require more staff. However, we have in our consideration of the wider framework applicable to regulation of the energy and utilities sectors come to the conclusion that a new comprehensive multi-service utilities regulatory body should be formed [combining] electricity, water and sewage but also…energy and possibly telecommunications, the housing sector in respect of tenant's rights and 'fair rents' for example and health and safety.

[132] TCIG Ministry of Housing Works and Utilities (2011), 'Extracts from Turks and Caicos Ministry of Housing Works and Utilities Report', relevant sections on Office of the Electricity Commissioner and Electricity department, draft unpublished, June.

Figure 6.2 presents a preliminary draft structure envisaged in the report (note also that the report does not discuss staffing). Here, a chairperson of the regulatory authority would be appointed to whom the various sector regulators/Commissioners would report. The Commissioners themselves would benefit from input from various advisory groups.

Figure 6.2 Potential multi-sector regulatory body



Source: Ministry of Housing Works and Utilities June 2011 report.

In relation to the model presented in Figure 6.2, a number of observations can be made.

– The Ministry of Works report does not fully specify the form of economic regulation to be adopted, or the powers of the regulator versus those of the Governor. Rather, the report focuses on how competencies and resources could be shared under a multi-service structure. For the reasons discussed above, it is important for all parties that the CEO of the regulatory authority (and the various Commissioners) is sufficiently independent of the TCI Government, and has sufficient powers.

– Care would be needed to separate government policy-making from the role of the regulatory body. As shown in Figure 6.2, the body would have a policy and research division, which would presumably feed into renewable energy research and development. However, policy on renewable energy is ultimately a matter for the TCI Government (specifically the DECR).

– The structure envisages hiving off the responsibilities of the Electricity Commissioner for inspections (and, in the case of other sectors, safety). This could be a valid strategy, as it would free up resources for the Commissioner to focus on economic regulation.

– While there is merit in having specialist advisory groups for each sector, it is not clear that these would need to be entirely separate. There could be some economies of scale in sharing of resources between the panels.

– Importantly, the multi-sector approach may not be the answer for TCI. Box 6.5 compares the merits of this approach with other resourcing strategies in a small-island setting.

Box 6.5 Multi-sector regulation versus other resourcing strategies in small-island economies

The multi-sectoral approach is one way that small jurisdictions seek to reduce costs in practice. Another means is to share costs with other jurisdictions. For example, regulatory authorities on the Channel Islands of Jersey and Guernsey have recently signed a Memorandum of Understanding concerning the share of resources.[133] In the Caribbean, the Regulated Industries Commission of Trinidad and Tobago is permitted to assist smaller islands on matters within its competence on a fee-for-service basis.[134] Regulatory cooperation between small islands in this region is also supported by multi-jurisdictional initiatives such as the Eastern Caribbean Telecommunications Authority, which complements the work of national regulatory authorities in five states (Dominica, Grenada, Saint Christopher and Nevis, Saint Lucia, Saint Vincent and The Grenadines) by promoting liberalisation and competition.

Resource costs may also be reduced by convening an adjudicative authority panel when a tariff review is requested, or otherwise required, as an alternative to having a permanent economic regulatory function. This is how electricity is regulated in St Lucia, where a review board is formed only when required for periodic review.[135] This avoids the need to maintain a continual focus on one sector when resources could be better deployed to other uses in the islands, although, arguably, this may come at the expense of developing sufficient knowledge of the sector.

Interestingly, Pollitt and Stern (2009) list strategies that might be used in smaller jurisdictions to mitigate regulatory resourcing costs. These include contracting out much of the detail of regulation to consultants, or undertaking cooperative expert exchanges with other regulators; using contracts and binding arbitration (in-country or externally); and using expatriate regulatory expert individuals or expert panels. Each of these options has its respective advantages and disadvantages.[136]

Source: Oxera analysis of various case studies.

Appendix 2 provides further analysis of other studies on the strategy and resourcing of regulators in selected Caribbean countries, albeit based on literature that in some cases may now be somewhat out of date. It is of note that both Trinidad & Tobago and Jamaica have multi-sector regulators, but that these are much large jurisdictions than TCI. In addition, in Appendix 2, while it is noted that the Jamaican experience has been successful, Trinidad & Tobago has experienced problems in attracting personnel. Hence, even very large Caribbean jurisdictions have issues attracting the necessary skills and resources to support regulation.

What therefore seems clear is that, because TCI is among the smallest of the Caribbean jurisdictions, it may not have the scope of ongoing activity across sectors and the population or tax base to justify the creation of a multi-utility regulator. It is also of note that the proposals of the Ministry of Works for the creation of such a body were not costed. While a multi-utility approach might be viable in TCI if in ‘skeletal’ form, involving extensive use of external consultants as and when required (in order to reduce set-up and fixed administration costs), it is unlikely to be sustainable as a stand-alone entity employing full-time staff in each of the sectors to be covered.

Indeed, using external experts for key phases of work, through outsourcing, would seem to be a more viable strategy, under whatever regulatory body is created.

[133] Jersey Competition Regulatory Authority (2010), ‘JCRA and Guernsey to share regulator chief’, Media Release, July 6th. The Memorandum of Understanding is available at http://www.jcra.je/pdf/110112%20MOU.pdf.

[134] Ehrhardt, D. and Oliver, C. (2007), ‘Big challenges, small states’, *Gridlines*, p. 2.

[135] Ibid., p. 3. Yarrow and Decker (2010), op. cit., recommend the wider use of adjudication panels in Guernsey.

[136] The context in the paper concerned was small developing economies, although the strategies appear relevant to small developed economies as well. See Pollitt, M. and Stern, J. (2009), ‘Human Resource Constraints for Electricity Regulation in Developing Countries: Has Anything Changed?’, EPRG Working Paper EPRG 0910 and Cambridge Working Paper in Economics CWPE 0914.

From discussions with stakeholders, it has also emerged that, historically, TCI has not cooperated as much as it might have with other Caribbean jurisdictions. There is merit in considering how sharing of ideas and resources with other Caribbean jurisdictions might benefit TCI going forward. For example, the CARILEC (2010) report, to which the Ministry of Works makes reference, notes the following:[137]

> There needs to be a stock of technical knowledge within the regulatory body to ensure that informed decisions can be made. Regulatory authorities should therefore invest in attracting, training and keeping good staff. Given the small scale in the Caribbean it may therefore be preferable to consider regulatory bodies covering multiple services (electricity, water, telecom, etc) *as well as* different countries (such as being initiated in the OECS). [emphasis added]

At the very least, greater sharing of experiences with other Caribbean jurisdictions would enable the Electricity Commissioner to gain a better understanding of alternative approaches to regulation, efficiency assessment, investment incentives and the economics of renewable energy. It also presents an opportunity for resource-sharing, secondments from other jurisdictions, joint aspects of work and, at the extreme, a merged body. It may be more difficult for TCI to adopt the OECS joint regulation route. The Eastern Caribbean islands have a common interest in the joint development of renewable energy and interconnection. As discussed, TCI is more remote, although joint initiatives with Jamaica and the Bahamas, among others, could be considered.

There is also merit in considering what funds might be available from external bodies to help set up independent regulation in TCI. Box 6.6 considers the example of The World Bank-funded Eastern Caribbean Energy Regulatory Authority (the regulatory body being considered in OECS, and as referred to by CARILEC).

Box 6.6 Eastern Caribbean Energy Regulatory Authority

The Eastern Caribbean Energy Regulatory Authority was launched by The World Bank in conjunction with the OECS, and has been endorsed by OECS electricity companies, CARILEC and CARICOM, with set-up costs funded by The World Bank.[138] The project is initially being set up across two countries (Grenada and Saint Lucia) at a cost of $5.6m. In future, additional countries may join and, while it is expected that these would cover any additional costs, there is also potential room for further World Bank funding.

The project involves pooling regulatory resources and sharing the fixed costs of regulation across participating countries. It seeks to provide stronger independent technical advice on electricity tariffs, licensing and policies. The World Bank identified a number of concerns with electricity markets in the OECS countries (some of which are similar to those in TCI). These include high costs due to the insularity and small size of systems; dependence on diesel; the level and volatility of tariffs; and lack of renewable energy and self-generation.

The two main objectives are to improve the regulatory framework for electricity sector governance; and to diversify the sources for electricity generation, including from renewables. The World Bank expects the project to generate the following benefits:

– maximisation of economies of scale in regulating the electricity sector;
– better utilisation of scarce human resources;
– increased capacity for regional electricity trade;
– electricity cost savings to consumers;
– less volatility in electricity tariffs in the longer term, by reducing reliance on diesel;
– greater regulatory certainty for utilities, investors and consumers;

[137] CARILEC (2010), 'Position Paper on Regulation and Renewable Energy: Minimization of Barriers and Provision of Incentives for Renewable Energy Technologies and Alternative Fuels'.

[138] This information here is based on an analysis of The World Bank (2011), 'Project Appraisal Document on Proposed Credits in the Amount of SDR 1.8 Million to Grenada and in the Amount of SDR 1.8 Million to Saint Lucia in Support of the First Phase of the Eastern Caribbean Energy Regulatory Authority Program', May 16th; The World Bank, 'Project Information Document. Concept Stage. OECS Regional Energy Planning and Regulatory Authority', Report No. AB4313 and The World Bank, 'Project Information Document. Appraisal Stage. Eastern Caribbean Energy Regulatory Authority (ECERA)', Report No. AB5178.

– increased regional integration across the OECS.

The project involves the following measures:

– improving public confidence in electricity sector governance through independent advice on tariffs and tariff-setting processes, balancing the needs of consumers and investors;
– improving the investment climate to facilitate renewable energy and cross-border trade;
– encouraging efficiency improvements through tariff regulation and performance benchmarking, while (potentially) encouraging best practice in fuel purchasing and fuel cost adjustments;
– encouraging greater scrutiny of generation capacity expansion plans, and requiring purchases from independent producers where this would lower total system costs;
– designing a common licensing policy and incentives for renewables investment by existing and new companies. (A single market across many states, and a common regulatory framework, may make renewables more attractive to private investors and manufacturers); and
– improving monitoring in terms of the release of data and in supervising compliance.

As regards the form and functions of the project, The World Bank has stated that:

– the project should operate with a lean staff using consulting services for a number of its tasks;
– the domestic regulatory structure should continue with its role of managing customer expectations and complaints, handling public consultations, and maintaining close contact with the electricity utility;
– in each participant country, two staff members should represent the project;
– the level of national representation in the project will be determined separately by each country, with the associated costs also being borne by each country;
– a dedicated budget will be set aside in the project for training purposes.

The Eastern Caribbean Energy Regulatory Authority project would respect the specific electricity sector policies of individual member states, while facilitating harmonisation and cooperation to encourage investment.

Interestingly, the power companies across the Caribbean have had the benefit of learning from the experience of others—for example, via CARILEC (in particular TCU)—and in terms of the operations of their parent companies across various jurisdictions. A new regulatory body might also seek to cooperate more with other Caribbean regulators, for example through CARICOM.

TCI Government would also need to consider what further training in economic regulation staff within the new regulatory body would require.

6.6 Institutions: including stakeholders in the process

6.6.1 Embedding stakeholder engagement into the regulatory regime

As noted in section 5.2, it is not clear at present that the companies engage sufficiently with their customers when planning their future investment programmes. Section 5.3 noted that there needs to be increased use of stakeholder engagement.

While both Fortis TCI and TCU have undertaken business case analysis, in terms of the potential cost-effectiveness of the proposed schemes, it is not clear that the companies have asked their customers about the options available or how much they would be willing to pay for improvements; doing so could increase both inclusivity and transparency. There is more generally a case for the companies to seek to engage with their customers on a day-to-day basis.

Consultation and negotiation are features of many regulatory regimes around the world (including under 'lighter-touch' cost of service regimes, for example in New Zealand, and in the Netherlands, and in rate-case settlements in the USA), and are increasingly being used in price cap regimes (including in the UK).

Any regime introduced would need to be proportionate to the TCI context and not too prescriptive. It would require that companies consult with their customers (and other stakeholders) to solicit their views, share information on investment proposals and the rationale, and demonstrate to the regulator that customers (and other stakeholders) want the investment and are willing to pay for it. This could be through meetings, interviews, surveys or other means. This could be introduced either under a revised rate base approach or under a new system of price cap regulation.

The regulator and companies would need to discuss what form of stakeholder regime should be put in place, together with the associated regulatory incentives and processes. An example as to how this could work under a price cap regime, with new legislation in place, is as follows:

– The company would be required to undertake stakeholder engagement in formulating their business plans.

– The company would aim to speak to, and balance the needs of, different customer interests (eg, hotels versus residential).

– The company would take account of government policy (eg, renewables).

– The company would seek efficient solutions to investment where users can be involved (eg, demand reduction and solar energy); and where third-party users can be involved (eg, wind energy).

– The regulator would assess whether the company has performed this engagement exercise adequately, and, if not, require the company to engage further.

Ultimately, it would be for the regulator to decide whether adequate engagement had taken place, and to balance the needs (in particular) of current versus future customers. However, where customers have clearly signed up to specific investment activities, it would be expected that the regulator would allow for these initiatives in the tariffs set (subject to other parameters, such as the WACC, efficiency, etc).

This exercise would improve transparency, and enable the companies to understand their customers better. However, it should also enable the company to identify options that are more efficient, and more in keeping with customers' needs. It would also improve the flow of information (both qualitative and quantitative) to the regulator in terms of what is efficient investment, when, and at what cost.

Given the small size of TCI, it should be possible to undertake meaningful stakeholder engagement with an appropriate diversity of stakeholders. It will be important to focus on the most important aspects.

6.7 Institutions: strategies for dealing with hurricane events

At present, there is no explicit mechanism in TCI to deal with restoration of the electricity network after a hurricane. At its recent rate review request, it was noted:[139]

> TCU has indicated that the main reasons for the request for a rate increase is the company's investment in the restoration of the distribution system after the passage of hurricane Ike in 2008. At that time TCU had invested significant amounts in the rebuilding of the system, without any financial aid from government.

The company argued that it was, partly as a result, not earning an adequate return on capital.

[139] Ajodhia, V. (2011), 'Report of the Commissioner of Inquiry into the Variation of Tariff Rates', TCU rate review, August 29th.

In practice, the Inquiry report did not recommend an increase in rates. This was because it was concluded that, in contrast to the views put forward by the company, 'TCU is currently earning a reasonable profit'. The report did not, in this sense, need to reach conclusions on whether TCU should be entitled to further funding as a consequence of Hurricane Ike.

Nonetheless, the Inquiry report had considered various views put forward on the issue. Members of the Chamber of Commerce and Consultative Forums were of the view that it was TCU's responsibility to finance restoration itself.[140]

TCU put forward the following position.[141]

> [The restoration] took about five months and was done with the assistance of other regional utilities through CARILEC's Hurricane Assistance Plan. This assistance enabled TCU to rebuild its system quicker and at a lower cost than what would have occurred otherwise. Even with this assistance, however, it cost over $ 4.5 Million to rebuild the distribution system. We are aware of several other jurisdictions (Cayman, Jamaica) in the region where this kind of expenditure has been dealt with through an adjustment to the rates or a specific surcharge. In the immediate aftermath of Ike, [we discussed with the Governor] whether or not there would be grant funding (the UK government had announced a multimillion dollar grant to the TCI in response to Ike) available to assist in the rebuilding of our system. We discussed…how, in the absence of such grant money, the rates would have to be adjusted to recover the sums being invested. The Governor told us that there would not be grant funds available for TCU; he understood clearly that this would have to be dealt with in the rates.

At present, there is no explicit provision in the Ordinance to provide for a rate increase in the event of a hurricane. The takeover agreements seem to indicate that the utilities are themselves responsible for all maintenance and restoration through their own financing at the prevailing tariffs. The provision for an increase in rates relates to whether the company is earning a reasonable return. As noted, the Inquiry report judged this to be the case.

Going forward, if price cap regulation (coupled with a building-block approach) were introduced, this would incorporate a best estimate of the required return that TCU should earn. More generally, there would be a pot of allowed revenue, based on a forward-looking assessment of likely costs (including efficiencies). Therefore, were a price cap/building block approach introduced, a more explicit mechanism than exists at present would most likely be required for dealing with hurricane events (which, in economic terms, are low-probability, high-cost, externally driven cost shocks). Two alternatives are:

– an explicit contingency within allowed revenues for potential hurricane events (at present, this is implicit);

– provision to re-open the price review process in the event of a hurricane (if, for example, this were material, *and* would not be financeable if dealt with at the next review).

As regards the 'contingency allowance' option, private insurance is unlikely to be available to TCU to deal with extreme hurricane events. However, what would be reflected in bills is a premium which would in turn be put into a reserve. This would be ring-fenced, non-distributable, and solely used to deal with extreme weather events. Once a sufficient amount had been paid into the reserve, further contributions would be suspended. The reserve fund would, in effect, act as a buffer in the event of a hurricane 'shock'.

The second option is to specify that, if a hurricane occurs leading to material damage to the network, which in turn significantly harms the financial performance of a utility, tariffs would then be reviewed to deal with the problem.

[140] Ibid., p.19.
[141] Ibid, annex.

The *advantage* of the contingency option is that it would smooth the impact of any potential bill increases. Customers would pay a modest contribution in each year in the knowledge that, should the worst occur, the utility could restore the network without needing to increase prices. Indeed, such an increase in prices would come at a time that consumers would face general financial hardship from the more direct effects on them as a consequence of the hurricane (loss of income, property and social hardship). It would also ensure that the utility is as expedient as possible in restoring the network.

A *disadvantage* is that consumers would pay upfront for a contingent event. It would also be necessary to ensure that the fund is suitably ring-fenced, and used for the intended purposes in an efficient manner and with regard to the right priorities. Effective transparency and governance would be critical. Moreover, the current incentive for an electricity company to restore power is that, in the absence of doing so, it would have no revenues.

Box 6.7 illustrates that a number of Caribbean jurisdictions have such reserve funds in place, and shows how these tend to operate alongside other initiatives, including contingency plans, coordination with other jurisdictions (and electricity companies in other jurisdictions), as well as regulatory involvement in how emergency funds are managed and used.

Box 6.7 Hurricane funds in other Caribbean jurisdictions

Hurricane funds have been established in Jamaica, Cayman and Grenada. In Jamaica, Jamaica Public Service Co. Ltd (JPS), with the approval of the Office of Utilities Regulation, has established a self-insurance fund, to cover damage to its network following a natural disaster, for which JPS is unable to obtain private insurance. JPS's licence also allows it, with the approval of the regulator, to recover these costs through electricity rates. Importantly, it is ultimately for the Office of Utilities Regulation 'to determine how these options are utilized, depending on the circumstances'.[1]

In Cayman, the Caribbean Utilities Company has a combination of private insurance and a special hurricane fund. The company has 'ample insurance to cover its damage and losses' in normal circumstances and a hurricane fund of $4m to cover deductibles and uninsured risks, a $7.5m line of credit for reconstruction, and a $10m bridging loan facility.[2]

Grenada has perhaps the most comprehensive package of contingency arrangements to deal with hurricane damage. The World Bank notes that GRENLEC benefited from a regional hurricane recovery programme established before Hurricane Ivan hit in September 2004, as well as a reserve fund for such natural disasters. GRENLEC also benefited from regional agreements already in place for mutual emergency assistance through the Caribbean Hurricane Assistance Program, 'the only utility agreement of its kind in the Caribbean'. Organised by CARILEC, the Program provides for 'the assembly, dispatch and coordination of emergency teams of linesmen from member utilities', to help restore networks in a jurisdiction affected by a serious hurricane. To be eligible for assistance and training, each utility pays an annual fee of $2,000 to the Hurricane Fund.

After Hurricane Ivan, GRENLEC sought assistance from the Caribbean Hurricane Assistance Program, which deployed 100 workers from across the Caribbean to help restore the network. In addition, GRENLEC had developed its own Hurricane Disaster Plan, allowing it to act immediately following a disaster (all GRENLEC employees worked continuously to bring power back on line). Further foreign assistance was also received (beyond the Caribbean Hurricane Assistance Program), with 20 power technicians deployed from Trinidad. GRENLEC had also, in the preceding eight years, set aside $750,000m a year in a disaster reserve fund. The company drew $6m from this reserve, and required only another $375,000 for the repair work. In combination, critical services to hospitals resumed almost immediately, and 18% of the electricity grid was restored within a month. Repairs to the entire grid were completed in April 2005 at a cost of $6m.[3]

Source: [1] http://www.myjpsco.com/disaster_centre/faq.php. [2] http://www.eclac.cl/publicaciones/xml/7/20507/L645-Parte 2.pdf. [3] http://siteresources.worldbank.org/INTLACREGTOPHAZMAN/Resources/grenanda_rebuilding.pdf.

A hurricane fund could be introduced separately for Fortis TCI and TCU, but only if sufficient safeguards were put into place. The fund could even be held in trust.

Finally, it is of note that the Economic Commission for Latin America and the Caribbean highlighted in 2008 that limited funding provision had been made at the macro level across various TCI sectors to deal with events such as Hurricane Ivan:

> A National Recovery Fund (NRF) that is informed by the experience of the Cayman Islands after hurricane Ivan would be useful to expedite repairs and reconstruction of houses for the poorer, uninsured segment of the population. Similar to the Cayman Islands, the Fund could be set up as a private, independent Trust to shield it from any perception of unfairness in the conduct of its affairs. Trustees should be held to high fiduciary duties with requisite penalties for breaching them. In prioritizing assistance, the needs of families with young children, old and infirm persons and other aspects of socio-economic deprivation should be addressed first.[142]

Any measures to address hurricane funding for the electricity sector specifically may need to be considered in relation to any changes to arrangements at the macro level.

[142] Economic Commission for Latin America and the Caribbean (2008), 'Turks And Caicos Islands: Macro Socio-Economic Assessment of the Damage and Losses Caused by Tropical Storm Hanna and Hurricane Ike', prepared at the request of the TCI Government, p. 71.

7 Deciding on the most appropriate model for TCI

In preparing this report, Oxera held discussions with the TCI Government regarding the emerging findings and options for reform.

To move forwards, the TCI Government is considering the institutional and resourcing structure to adopt for electricity regulation, and whether regulation should be based on incremental changes to the existing rate-base regime or on more fundamental changes such as price cap regulation. It has identified concerns with introducing a multi-sector regulator in TCI, and with introducing more fundamental reforms to regulation.

7.1 A recap: incremental or fundamental reform?

Before exploring these issues further, it is perhaps first useful to provide a recap of some of the analysis presented in sections 5 and 6. Section 5.1 set out principles for regulation, and examined whether the existing regime met them and hence was appropriate. Section 5.2 concluded that this regime 'fell short' in a number of respects.

Section 5.3 then considered what changes to the regime would better meet the principles identified, including the advantages and disadvantages of modifying the existing system of rate-base regulation—albeit under the existing Ordinance—compared with a more radical departure, including the introduction of price cap regulation (see, in particular, section 5.3.2).

While modifications to the existing rate-base regime were identified that could improve the current situation, it was noted that these might not go far enough to address the identified shortcomings—for example, in relation to incentivising operating and capital efficiency.

More independent regulation, coupled with a price cap approach, could instead be introduced (albeit with pass-through for uncontrollable costs). This was found to have more powerful incentives for companies to become efficient, and would reveal information on costs through company behaviour. Nonetheless, it was noted that price cap regulation in TCI could not, and should not aim to, replicate the extent of detailed analysis observed in larger jurisdictions. Rather, the approach would need to be proportionate to the situation in TCI, in terms of its scope, the information requirements, and who does what.

In practice, this would require addressing what is typically involved in setting up a price cap regime but considering the TCI-specific situation. However, it also needs to be recognised that operating effective rate of return regulation using a modified rate-base approach would require additional regulatory input and analysis (see section 5.3).

Section 6 then looked in more detail at what changes to the regulatory regime might look like in practice. In particular, section 6.3 examined how the price control approach could be applied (as an alternative to incremental changes to the current rate-base approach). Section 6.4 examined issues regarding the establishment of an independent economic regulator, and the regulatory style and powers that might be adopted in TCI. Section 6.5 then examined alternative resourcing strategies for the regulatory body, taking account of the fixed costs relative to population size in serving a small island. One possibility was a multi-utility regulator, which was recommended in June 2010 in a draft analysis by the Ministry of Works. However, other strategies examined included outsourcing during heavier periods of work by the regulator, and greater collaboration with other Caribbean states.

Some of the issues discussed in section 6 have been left open for further consideration by the TCI Government, including renewables policy, funding and treatment within the regulatory framework (section 6.1), and the approach to hurricane events (section 6.7).

7.2 Weighing up the advantages and disadvantages

The TCI Government has two main concerns with some of the more fundamental options for reform discussed in section 6:

– a ‘multi-sector regulatory agency’, as proposed by the Ministry of Works, could be too costly to implement in TCI given the size of the jurisdiction;

– a ‘purer’ form of price cap regulation, compared with incremental modifications to the existing approach, would not deliver sufficient benefits in relation to the costs and risks involved because of the additional resources and activities required.

It has therefore asked Oxera to provide a judgement on how the advantages and disadvantages of following a multi-utility/price cap approach (hereafter model ‘A’) compare with maintaining the existing rate-base regime with some incremental modifications (hereafter model ‘B’). Oxera understands that these are the two main regulatory policy options now being considered by the TCI Government.

At the centre of this debate is whether, compared with model B, the additional benefits (eg, in the form of greater OPEX and CAPEX efficiency) implied by model A would be expected to outweigh the potentially greater, and more uncertain, costs that could be involved.

In making this judgement, it is necessary first to define what level of evidence needed to meet the requirements of an ‘acceptable’ regulatory outcome as implied by models A and B, and how this is likely to influence the costs of setting up and administering each model. For example, to the extent that model B relies mainly on historical information (to set future prices) that is readily available, as opposed to seeking to predict a number of factors that are then used to set future prices under model A, the costs of implementing model B would be expected to be lower. Deriving future projections to be used in tariff-setting (eg, costs, electricity demand), in the case of model A, is likely to require more extensive research and analysis.

However, model B may not be purely backward-looking. Under a rate-base approach, if the regulator has the power to review ex post whether CAPEX or OPEX has been undertaken *efficiently* (or, ex ante, whether it will be efficient in future), an element of future projections is brought back into the regulatory process. Generally, only ‘pure’ rate of return regulation—in which the firm always recovers its expenditure—can be based entirely on historical data.

Given that the appeals route for any future ‘rate review’ process under models A and B is uncertain, the standard of evidence that would need to be applied in either case is also somewhat uncertain at this time. Following discussions with the TCI Government, Oxera’s judgement on the standard of evidence sought by the TCI Government, in making its policy decision between models A and B, is based on the following assumptions.

– The methodologies employed in estimating the relevant parameters in a rate review, under model A or B, should be consistent with established ‘best practice’ seen in other jurisdictions, or which would otherwise have a sound theoretical and empirical rationale.

– The rate review process, under model A or B, would be based on data submissions from the companies that are pre-specified or could otherwise be reasonably expected to be collected by the companies in the course of normal operations.

– A rate review, under model A or B, should be capable of being finalised within, say, 2–4 months of commencement (including allowing for at least one round of consultation with the stakeholders before the regulator makes its judgement); something that would naturally curtail the amount of evidence that could be analysed and integrated into the review process. For the purposes of this assessment, it is assumed that the regulator has access to qualified and independent economic and engineering advisers to carry out the rate review.

The last assumption is challenging for introducing either model A or B, but particularly in the case of model A. At the same time, it would not be necessary for the regulator to adopt all the initiatives discussed in section 6.3 and 6.4 that could support model A, and the companies already collect some of the information, which could be built upon to support model A.

Model A would otherwise be broadly in line with the more fundamental reform options presented in section 6: introducing a price cap regime for undertaking rate reviews, coupled with a building block approach; establishing an independent economic regulator, with a particular regulatory style and powers; and potentially establishing this body as a multi-sector regulator.

This model would involve *several* changes to the existing Ordinance and regulations. The multi-sector regulator approach was, however, presented as one among several strategies to manage the costs involved in setting up and administering a different regulatory regime, and was regarded as a strategy that might not be well suited to TCI.

Model B would not (necessarily) involve establishing a multi-sector regulator, but would still involve creating an independent electricity regulator. In turn, this body would rely on the use of external experts by outsourcing certain activities and tasks required at the time when tariff reviews occur. Under this model, the regulatory regime would also be largely based on the existing rate-base approach, but with the following modifications:

– implementing a rate-base review every three (to five) years;
– adopting a more robust approach to the treatment of fuel costs in the rate base and fuel cost pass-through mechanism;
– determining with more robustness and clarity the appropriate return on capital and asset base;
– undertaking more robust CAPEX assessment;
– facilitating the integration of renewable generation by independent power producers.

Section 6.3.1 indeed noted that there were benefits to the existing regime. For this reason, some measures that could be undertaken under existing regulation and legislation were considered.[143] However, Oxera understands that what the TCI Government is proposing under model B would require changes to the Ordinance. In some ways, therefore, model B is consistent with the measures discussed in section 6.3.1, which listed changes possible under the existing Ordinance and voluntary initiatives. In other ways, model B contains components of the price cap framework discussed in sections 6.3.3 and 6.3.4, albeit in significantly simplified form.

7.3 Model A: multi-utility + ‘price caps’

The key features of model A are described in Table 7.1 below. In summary, this model would involve the following institutional framework:

– an independent economic regulator with duties, and the discretion to interpret those duties, to set prices and demand information from the companies (while recognising that achieving ‘full’ independence in a small-island context may be challenging);

[143] It was noted that these changes may not radically alter the incentives present under the existing regime with respect, say, to CAPEX or OPEX efficiency. Many of the changes would rely on voluntary initiatives that the companies may or may not sign up to.

– a multi-sector approach to regulation along with greater cross-Caribbean collaboration and use of external consultants as required to advise the regulator on certain technical matters;
– adoption of staggered rate reviews across the various sectors regulated by the multi-sector agency to increase the utilisation of TCI Government resources;
– the companies would perform most of the tasks to input into the price-setting framework (eg, business planning, engagement, CAPEX planning, OPEX and KPI reporting), subject to regulatory guidance and oversight;
– examples of tasks that the regulator would engage in (or ask external advisers to assist with) would include setting the allowed return,[144] reviewing the rate cases put forward by the companies, and setting prices using an appropriate formula (eg, RPI – X).[145]

The regulator would, however, need the capability and resources to prescribe and assess the information requirements concerned within this discretion-based framework. Viability of this model is contingent on there being a policy commitment to adopting a more or less standardised regulatory framework across a number of sectors in TCI, while recognising sector-specific challenges.

The price cap/building block approach has the following advantages.

– At present, the electricity companies have an informational and resourcing capacity advantage over the regulator. The price cap approach (which incentivises efficient costs, and the revelation of such costs), combined with the powers implied under the above institutional arrangements, could help to address these asymmetries.

– While the current rate-base approach arguably resembles a nominal price cap—in that base rates have not been revisited for some time—company behaviour regarding past expenditure and future expectations of the allowed return is not consistent with the incentives that occur under a price cap. A price cap regime would provide a basis for establishing more appropriate incentives. For example, there is currently an expectation that *any* escalation in CAPEX will at some point be reflected in rate base adjustments, and that a return of 15% or 17.5% (depending on the company concerned) will be earned on that CAPEX. Indeed, the debate over the allowed return has become legalistic in nature, rather than being based on the evidence of the underlying risks and returns expected of investors today.

– Disagreement between the companies and regulator on issues under the current rate base approach already takes up time and resources, which could be better spent on a well-functioning price cap review process aimed at calibrating the incentives for efficiency in asset operations and investment. Indeed, it is not clear that all recent and planned investments are efficient, since existing legislation does not require electricity companies to justify their CAPEX plans before or after the event.

– While it is not obvious that the companies are inefficient on OPEX (eg, based on labour productivity measures, and given their small size; see section 3), there is likely to be some scope to be efficient on controllable OPEX, given that companies have never been given explicit incentives to achieve greater efficiency. Indeed, the existing legislation does not require regulator to examine whether companies are efficient.

[144] The allowed return is often determined by estimating the cost of capital of the regulated entity, taking into account the benchmark returns of both debt and equity capital through the WACC.

[145] This formula, or a variant of it, is typically used in price cap regimes. For example, different inflation indices are used to reflect changes in retail (consumer) prices, producer prices or construction prices, depending on the context. The choice of index is based on a trade-off between the need to reflect changes in the general level of costs of a regulated entity, and to avoid indices that would be influenced by the actions of the regulated entity itself. For instance, if a company is a large purchaser of a commodity used as an input to its production process in a relatively small geographic market, this may drive up the price that commodity. In turn, if the prices of the company's own goods and services were indexed to an inflation measure that is influenced by the price of that particular commodity, the incentive to increase the efficiency with which it consumes that input commodity could be weakened significantly.

– Adopting a price cap regime would be consistent with precedents seen elsewhere in the Caribbean (eg, Grenada, Jamaica), providing some opportunities for sharing of best practice.

However, as emphasised in section 6, price cap regulation, if adopted, should not be applied in TCI in the more complex way it is applied in larger jurisdictions—that is, it should be tailored to the specific TCI context.

The TCI Government has identified a number of problems with model A, which could be regarded as disadvantages of the price cap approach:

– the multi-utility regulatory agency approach would be too costly;
– price cap regulation has measurement issues (eg, determining RPI), is too complex for TCI, and its main benefits would in any case be realised only in the case of controllable (non-fuel) costs;
– the case for price cap regulation rests on there being future efficiency gains that can be realised, but thus far the evidence on this is inconclusive.

These issues are discussed by Oxera in turn.

On resourcing issues, as TCI is among the smallest of the Caribbean jurisdictions, it may not have the scope of ongoing activity across sectors and the population or tax base to justify the creation of a multi-utility regulatory body. In addition, the Ministry of Works proposals for a multi-utility regulator were not costed. Even very large Caribbean jurisdictions have issues attracting the necessary skills and resources to perform this role. While a multi-utility approach might be viable if in 'skeletal' form and involving extensive use of external consultants where required (in order to reduce set-up and fixed administration costs), it is unlikely to be sustainable as a stand-alone entity in TCI employing full-time staff in each of the sectors to be covered. Outsourcing of key tasks, when required during busy times, may be a more viable option.

Table 7.1 Model A features

Features	Observations on viability
Substantive modifications to Ordinance, regulations and status of takeover agreements	Major legal and contractual issues
Independent economic regulator with the final say on tariffs	True independence is difficult in a small-island context, but more independence than exists at present is possible
Creation of a multi-utility structure, as set out by the Ministry of Works	This is not a valid strategy by itself (it would need to be combined with other cost-mitigation strategies, such as closer Caribbean cooperation and/or using external consultants). It would incur-set up costs and recurring costs, especially if full-time personnel are employed without the use of external consultants as needed
Regulations (not the Ordinance) set out how tariffs should be set	Enables tariff-setting approach to be adjusted over time without modifying the Ordinance
Tariffs set every N years (eg, N = 3 at first, 5 later)	Intensive period of work every 3 to 5 years
Forward-looking cost assessment at price reviews with the regulator having the ultimate decision on how to set prices ex ante, based on its broad duties	Provides regulator with power to assess appropriate costs and returns based on merit, or to ask external experts to do so within this remit. However, there are concerns remain regarding regulatory capabilities and discretion
RPI – X for non-fuel base costs (T1) (ie, requires the regulator to *predict* the level of future costs over the price control period)	Requires the measurement and projection of RPI (CPI) or some other form of capturing general levels of inflation. Requires projections of OPEX, CAPEX and financials
Separate fuel base cost allowance taking account best estimate of fuel costs (T2)	Quite simple for this to be constructed. Requires monitoring (as at present). Compare purchasing behaviour of TCU and Fortis TCI
Improved fuel cost adjustment mechanism (T3) (eg, up-to-date fuel efficiency factor, economic purchasing obligation, smoothing requirement)	Quite simple for this to be constructed. Requires monitoring (as at present). Compare purchasing behaviour of TCU and Fortis TCI
Regulator has powers to require companies to undertake customer engagement and set out business plans (covering outputs, CAPEX, OPEX, WACC, etc), although the companies can choose which aspects to focus on	Requires regulator to prescribe information required based on merit and to be able to absorb and assess the quantity of responses (possibly with the help of external consultants). The regulator can choose what the main focus should be in asking for information
Establishing the initial RAB based on merit using a broad remit	Having a RAB helps encourage certainty for the companies and their investors, especially in relation to investment in utility-scale renewables. The RAB would need to be assessed by the regulator (possibly with the help of external consultants) and jointly agreed with the companies.
Establishing the WACC based on merit using a broad remit (not as per the current debate concerning the takeover agreements)	The regulator has powers to determine the WACC (possibly with the help of external consultants). This may raise concerns regarding regulatory discretion
Requirement for companies to undertake OPEX efficiency analysis and demonstrate efficient CAPEX (including site visits and KPIs)	Companies would undertake the analysis and demonstration, while the regulator would review these. Requires regulator plus support (or external consultants) to set out guidance and assess the information provided
Quality of service tables and/or mechanisms	Requires regulator to be able to set out the metrics and the reward/penalty mechanism, or agree this with the companies
Powers for the regulator to demand information between price reviews, as required	Requires regulator to be able to prescribe what information it requires based on merit and to be able to absorb and assess the quantity of responses, possibly with the help of external consultants
Revised obligations for companies to comply with their licence	Depends on enforcement

Source: Oxera.

On the above issues specific to price cap regulation, it is worth recognising that there are some difficulties in creating an inflation index for TCI. That said, it may acceptable to use a (pre-existing) regional index or an index based on the US CPI (with suitable adjustments derived from historical relationships between the US CPI and one or more other regional indices). However, this may be more costly to establish in terms of resources and robustness (and would be a criticism that the companies could level at model A, necessitating careful assessment of the viability of this approach before implementation).[146]

In relation to complexity, price cap regulation can be as simple or as intricate as desired. Sections 5 and 6 emphasised that this form of should not be applied in TCI in the same way it is in larger jurisdictions (eg, as implemented by the electricity regulator in Great Britain). Rather, the focus should be on the regulator 'doing a few things well'. The regulator would have powers to demand the most important information necessary to perform its duties. Where they are best placed to do so, the companies (not the regulator) should prepare information and undertake analyses to help regulation work. For example, Fortis TCI already prepares business plans and KPIs for internal purposes, and both companies have participated in the CARILEC benchmarking initiative. It would also not be necessary for the regulator to adopt all of the initiatives discussed in sections 6.3 and 6.4.

Nonetheless, a problem could arise if the regulator becomes burdened with too much information to assess. In addition, using a rules-based approach within a price cap system has some advantages over a discretion-based approach (as discussed further below).

On the issue of the current and future efficiencies that might be realised, the lack of sufficient robust comparative data limits the extent to which it is possible to make a judgement in this regard. As explained in section 3, due to their small scale and consequent operational choices (plant mix, fuel choice, labour costs, and reserve capacity), the TCI companies are not like-for-like comparators to other jurisdictions. Higher-level benchmarks were explored (eg, labour productivity), adjusting for scale. The incentive for the companies to be efficient on CAPEX has been questioned in this report. The escalation of OPEX overheads by Fortis TCI has also been identified as a potential issue.

However, it would be for the regulator, once in place, to explore these issues further. The regime, once tariffs are set, would also reveal efficient costs. Notwithstanding this, it cannot be guaranteed that introducing price cap incentives would generate significant future CAPEX and OPEX efficiencies, and it is worth considering the risk if they do not. Whether it would be worth bearing this risk would depend partly on whether there was perceived to be value in regulating other sectors more carefully and to a higher standard of evidence than has traditionally been the case in TCI. For example, whatever the outcome in terms of reducing electricity tariffs, the process of setting price caps for the electricity sector could provide the TCI Government's appointed regulatory staff with important experience in gathering information on costs and operational performance, financial analysis, analysis of regulatory policy issues, and negotiating with utility providers, which may be useful in a range of other contexts. It is conceivable that these skills and experiences could help to achieve more effective negotiation between the TCI Government (acting on behalf of consumers) and private sector providers in areas of relevance to the wider economy (ie, the regulation of other public infrastructure such as airports, seaports, healthcare, and water and sewerage services).

[146] While the selection of an appropriate inflation measure is sometimes a challenge, it is by no means an insurmountable one. It is likely that many businesses in TCI will have formed some view of inflation expectations for business planning purposes. It would be surprising if Fortis TCI and TCU, which procure, build, finance, and operate large and long-lived capital assets, do not have a view of inflation expectations.

7.4 Model B: Stand-alone and outsourced + modified rate base

It is important to recognise, as Oxera does, that some of the benefits of the price cap approach could be achieved with less fundamental changes to the existing regime. However, model B would still require modifications to existing Ordinance and regulations, and agreement on the status on the takeover arrangements.

Oxera understands that model B would include the following institutional features:

– the creation of an independent economic regulator (while recognising that full independence in a small-island context is difficult to achieve), but with regulatory activity that would involve extensive outsourcing during the periods when this input is needed (eg, every three years);
– a rules-based approach prescribed in the Ordinance, or in regulations, setting out the criteria for assessing the RAB, allowed return and CAPEX, and the information required by the regulator (external advisers would also need to pay regard to this);
– the provision of input by the companies into the tariff-setting framework (eg, business planning, engagement, CAPEX, OPEX, KPIs);
– tariffs would be decided every three years by an independent party on behalf of the regulator, and these would be binding (and not subject to further review by the Governor, except perhaps in pre-specified exceptional circumstances, such as following a severe hurricane event).

Specifically in relation to outsourcing, it is envisaged that external advisers would provide advice mainly as follows:

– financial/regulatory advisers would provide advice on RAB and WACC issues;
– engineering experts would provide advice on engineering issues, including CAPEX efficiency (this would probably also require site visits);
– external regulatory experts would provide some further advice on efficiency issues using higher-level data.

Key features of Model B are described in Table 7.2 below. In setting rates for three years, it would be necessary to keep base rates flat or apply a notional index (weighing up future potential inflation against potential efficiencies relative to inflation) in the three-year forecasts of allowed revenues.

Some of the analysis required to make model B operational is also required for model A, once model B moves away from just accepting all expenditure by the firm as being remunerated.

Model B seems to be a hybrid between a price cap (ie, model A) and a pure rate of return regime. Nominal base rates would remain fixed for three years and there could be some check on efficiency. However, the setting of base rates would be more rules-based, using past experience. It would be inherently less forward-looking than under a price cap approach, and, to the extent that mistakes were made in matching revenue to costs in the price control period, these would be corrected in the next period.

Advantages of model B include the following:

– it avoids the need to calculate an explicit RPI or CPI, but may still need to factor in an implicit inflation contingency in nominal base rates (weighed against implicit real efficiencies); otherwise, base rates will be more volatile when future rate reviews occur and, in periods of high inflation, holding base rates fixed could also pose financial risks;
– fuel cost incentives are more or less the same as under model A;
– while it would still require changes to the Ordinance and regulations (it is not just an extension of the existing regime), these would be less extensive than under model A;

- the institutional set-up could be lower-cost than model A, probably requiring few (if any) additional staff compared with the status quo, albeit with some additional external advisory support being used to conduct rate reviews;
- there would probably be a less onerous information requirement in between rate reviews than would be the case for model A;
- it could still potentially tackle the overcapitalisation incentive if the regulatory powers exist to question historical and prospective CAPEX, or if the regulator had powers to review 'large' CAPEX programmes before they are implemented. (However, this makes the regulation more complex and requires significant analysis to establish whether expenditure has been inefficient);
- setting out allowed return and asset based measurement criteria can improve regulatory certainty for companies, but may generate some inflexibility over time;
- as noted, it is not clear that the companies are necessarily inefficient on OPEX (although this is a possibility), and volume growth going forward looks more limited than in the past (a source of savings through scale economies). It is inherently uncertain whether price caps (ie, model A) would generate significant additional efficiencies over and above B (which in any case captures a number of the price cap/building block features); and
- provided that it tackles the key issues of the appropriate level of return and CAPEX accumulation (in future), model B may be a good compromise—that is, it has some features of a price cap, but may be better suited to the context in TCI.

Potential concerns with model B are as follows:

- the existing rules-based approach is too legalistic and process-driven, and has resulted in disagreements between the TCI Government and the companies in relation to its implementation. For example, arguments persist over the interpretation of the Ordinance, regulations and takeover agreements. It would be necessary to get the rules and criteria correct under a rules-based approach (as opposed to one that involves more discretion). The risk is that any set of rules would eventually (perhaps too quickly) become outdated, and updating the legislation too frequently could then increase perceptions of political risk;
- there is less scope for the regulator to demand information, or make decisions based on the merits of a particular case, except where these are not captured by the rules;
- a 'reasonable' standard needs to be reflected in the rules, rather than the assessment of what is reasonable being based on the regulator's general duties;
- it is not clear just how 'forward-looking' rate-base assessments would be, or whether the approach reveals efficient costs in the same way as a price cap. It would still be a rate-base approach to target a given return (although there is debate in recent rate cases over what the existing legislation allows on efficiency assessment—eg, the recent TCU review). What is clear, however, is that the incentives and checks implied under model B fall short of a price cap regime such as model A, and that model B leans towards being a cost of service contract;
- related to the above point, there are no explicit ongoing efficiency incentives or targets built into model B as there are under model A;
- the rules risk being incomplete, and the regulator and/or external consultants would *still* need to look at issues in setting rates that go beyond the specific issues covered in the rules. There could be disagreement on the level of discretion available to the regulator in areas not completely covered by the rules;
- sporadic use of external consultants may mean less scope for the regulator to retain skills internally, thereby foregoing the potential benefits associated with regulating other sectors more carefully and to a higher standard of evidence than has traditionally been the case in TCI.

Table 7.2 Model B features

Features	Observations on viability
Certain changes to the existing Ordinance and regulations, and clarity on status of takeover agreements	Certain legal and contractual issues
Independent economic regulator with final say on tariffs	True independence is difficult in a small-island context, but more independence is possible than is currently the case
Single regulator with extensive outsourcing when rate reviews occur	Lower-cost than multi-sector regulator and price cap; but less skills retention and ongoing monitoring capability
Ordinance or regulations set out criteria for assessment of rate cases	If Ordinance prescribes the approach, this may be difficult to adjust over time; as might be any regulations that are legally prescribed by the Ordinance
Planned and periodic adjustments (eg, taking place every 3 years) to base-rate tariffs and the fuel cost adjustment mechanism	More limited assessment than price cap, especially if all expenditure by the firm is automatically recoverable through prices
Mainly backward and current assessment of costs in rate cases (with some forward-looking assessment)	More limited assessment than price cap, but can easily involve issues of judgement around whether past expenditure was efficient, and should therefore be included in the future price limits
Pre-specified rules and criteria (set out in the Ordinance or regulations) for calculating an appropriate rate of return	These reduce regulatory discretion, and can steer external consultants. Care is required in the design of the framework. The framework also requires external financial/regulatory experts. It requires a WACC calculation at each tariff-setting point unless the rate of return is set once for a long time period
Rules and criteria (pre-specified in the Ordinance or regulations) for calculating a utility's asset base	Reduces regulatory discretion. Steers external consultants. Care required in design. Requires external financial/regulatory experts
Pre-specified rules and criteria for assessing the 'prudence' and efficiency of CAPEX undertaken to date (or in the course of the past regulatory period), and in future, at rate reviews	Reduces regulatory discretion. Steers external consultants. Care required in design. Requires external engineering experts. The more the regulator can adjust prices to take account of a firm's efficiency, the more analysis and judgement are required and the more complex the analysis will be
Separate fuel base cost allowance taking account best estimate of fuel costs (T2)	Quite simple for this to be constructed. Requires monitoring (as at present)
Improved fuel cost adjustment mechanism (T3) (eg, up-to-date fuel efficiency factor, economic purchasing obligation, smoothing requirement)	Quite simple for this to be constructed. Requires monitoring (as at present)

Source: Oxera.

Some final observations on Option B are as follows:

– **standard of evidence**—to meet the standard of evidence referred to in section 7.2, it is envisaged that guidelines would be needed on the methodologies for assessing key parameters of the tariff review. As a guide, regulatory authorities in the Netherlands and New Zealand could provide a model for how to measure parameters such as the allowed return and RAB, and how costs should be allocated to inform these assessments. Such criteria should perhaps not be included in the TCI Ordinance, but rather contained in secondary regulations referred to by the Ordinance.

– **CAPEX criteria**—it is difficult to be prescriptive on these, given the myriad of technical issues involved in assessing the costs (eg, over the short and long term, especially given uncertain demand growth) and benefits (eg, perceptions of quality of service by customers) of a particular asset that is part of an integrated electricity system. However, general criteria can be set out for appraising CAPEX, which cover issues such as the following.

- What is the quality of the company's business plan?
- Has the company clearly explained its strategy?
- What is the quality of the company's forecast of CAPEX drivers in future (eg, demand)?
- Has the company engaged with its customers and listened to their needs (what evidence is there of this)? Has the company considered an adequate mixture of options for meeting future drivers of CAPEX at least cost?
- What level of risk (and reliability) has been assumed by the business in doing so (is this appropriate)?
- To what extent has the business relied on quantitative modelling versus anecdotal evidence in forecasting CAPEX?
- How does the planning process compare with best practice?
- What evidence has the company put forward on its CAPEX efficiency?

- **resourcing strategy**—section 6.5 listed strategies for a small-island economy in terms of resourcing regulation at least cost. Model B would involve more outsourcing, as and when the above types of input are required. However, for continuity, it would still require an ongoing presence, with many activities still performed in-house.

7.5 Conclusions

In the above, Oxera has qualitatively considered the advantages and disadvantages of models A and B. In particular, the implications for resourcing, degree of regulatory discretion required, potential opportunities for efficiency improvements in the TCI electricity sector, and measurement issues in the TCI context have been discussed.

In framing the policy question over what kind of regulatory model (ie, model A or B) would be most likely to be suitable for TCI, it is perhaps easiest first to consider the benefits that model B could bring, and then whether the additional benefits (eg, in the form of greater OPEX and CAPEX efficiency) implied by model A would be expected to outweigh the potentially greater, and more uncertain, costs that could be involved.

What seems more certain is that a multi-sector regulator would not be the optimal solution (see section 6.5). The uncertainty over what other sectors (apart from electricity) such an organisation would regulate, how quickly (and if at all) such legislative reforms could be achieved, and what the benefits would be in terms of efficiency improvements also highlight that sector-specific regulation is expected to be worth retaining. As to whether it would be worth bearing the risk of setting up a multi-regulatory agency, this would depend partly on whether there was perceived to be value in regulating other sectors more carefully and to a higher standard of evidence than has traditionally been the case in TCI. For the purposes of this assessment, Oxera has discounted these potential sources of benefit.

However, there is still a choice between adopting elements of models A and B based on other aspects of these models. In this regard Oxera considers that implementation of model B would be expected to result in a number of regulatory reforms that would have a reasonable probability of addressing the primary concerns associated with the existing regulatory framework—that is, the allowed return determination, CAPEX assessment, transparency, and the perceived (in)appropriateness of the current working of the fuel cost adjustment.

While there could be incremental benefits of the fuller price cap mechanism associated with model A, it is not clear that it would result in future efficiencies over and above those capable of being achieved in model B. Option B may therefore be preferable since the incremental benefits of model A are likely to be low, whereas the costs could be somewhat higher (in terms of time and human resources).

However, as model B attempts to address the issues around efficiency, and starts to look forwards as well as backwards, rather than simply guaranteeing that the electricity companies recover their incurred costs through time, the complexity (and the associated costs) of model B starts to approach that of model A.

Furthermore, as noted above, model B would still be expected to require some changes to the existing Ordinance and regulations to be implemented and greater clarity achieved over the terms of the takeover agreements. In other words, implementing model B is not likely to be an entirely ‘costless’ exercise.

A1 Financial analysis

This appendix illustrates the assumptions that underpin the financial analysis presented in section 4, focusing on the principles of profitability assessment and the cost of capital calculations.

Profitability indicators

Regulators, competition authorities, and financial analysts have also tended to use a number of proxy profitability indicators, a sample of which (alongside IRR and NPV) is detailed in Table A1.1.

Table A1.1 Sample of profitability indicators

Profitability measure	Description	Comments
IRR	Discount rate that equates the present value of an activity's sum of expected stream of cash flows to its initial capital outlay	Conceptually correct measure of profitability, but requires robust cash-flow data and accurate asset values
NPV	Present value of a stream of future cash flows and terminal asset value discounted at a suitable rate	Conceptually correct measure along with the IRR. Popular measure in state aid investigations
ROCE	Ratio of EBIT to capital employed	Accounting measure of profitability and widely used in regulatory investigations. Provides same result as the IRR in the event of robust accounts and correct asset valuations
ROE	Ratio of net earnings (after tax) to equity capital	Accounting measure of profitability used as a proxy/check to ROCE analysis
Return on sales (ROS)	Ratio of EBIT to value of goods sold	No theoretical foundation, but eliminates the need to estimate asset values and is used for industries where few fixed assets are employed
Profit margins	Various measures of analysing profits using gross margins, total return to shareholders or Tobin's Q	Can be applied when the IRR is difficult to estimate. Total return to shareholders and Tobin's Q provide a measure of (predicted) forward-looking profitability.

Source: Oxera (2003), 'Assessing profitability in competition policy analysis', report for the Office of Fair Trading.

In the UK, for example, regulators and competition authorities have tended to use the ROCE/ROE, ROS analyses. Estimates of ROCE have often been based exclusively on accounting information since this is the most readily available information. In addition, one of the limitations to the use of IRR has been that this analysis extends over the life of the investment, while competition authorities and regulators are usually concerned with the companies' profitability assessment over a limited time period.

However, the economic literature has shown that if the IRR is the discount rate that makes the NPV of a series of cash flows from a business or activity equal to zero over the life of the investment, it is also possible to measure profitability over a discrete period of time (eg, less than the whole economic life of the investment), by using a truncated IRR. This measures the IRR over a certain time period by taking the opening asset value (ie, capital employed in the first year of the analysis) as a negative cash outflow, including all the cash flows generated by the asset during the period concerned, and then using the closing asset value as a cash inflow. The key steps in estimating the IRR comprise calculation of cash flows and the asset valuation.

Cash-flow information should be available at the level of the investment, segment or business being evaluated.

The correct measure of the asset value should be assessed according to the value to the owner principle, as explained in Box A1.1.

Box A1.1 The value-to-the-owner principle

The value-to-the-owner principle states that the value is the lowest of the economic value and the replacement costs. The economic value is the highest between the net realisable value (NRV) or the present value of net income from the continued use of the asset. The rationale behind the principle is as follows:

– if the economic value is higher than the replacement cost, the asset is worth replacing and the replacement cost is its value;

– if the NRV value is lower than the replacement cost, but higher than the present value, the asset should be sold and the net proceedings from the sale represent the asset value;

– if the present value from continued use is higher than the NRV but lower than the replacement cost, the value of the highest value of the asset is in the continued current use, and is equal to the discounted stream of net income.

In this context the replacement cost is elicited at the MEA value. This is the value of purchasing assets that provide the most efficient configuration using current technology to deliver existing services at their lowest cost.

An NRV above the MEA value is unlikely to persist as firms would make a profit from selling their assets and buying new ones, while would result in the NRV approaching the MEA value. Furthermore, in a competitive market the present value is also unlikely to be persistently higher than the MEA value, as new entry of firms would reduce the returns earned on assets, thereby reducing the present value to approaching the MEA value.

The calculation of the IRR on the basis of the MEA value provides the correct profitability measure to be compared against the competitive benchmark.[147]

While proxy profitability measures such as ROS have no theoretical foundations, profitability measures such as ROCE or ROE have a link to the IRR.[148] It has also been shown that the assessment of economic profitability using ROCE would require the use of the MEA value as the basis for the asset valuation.[149]

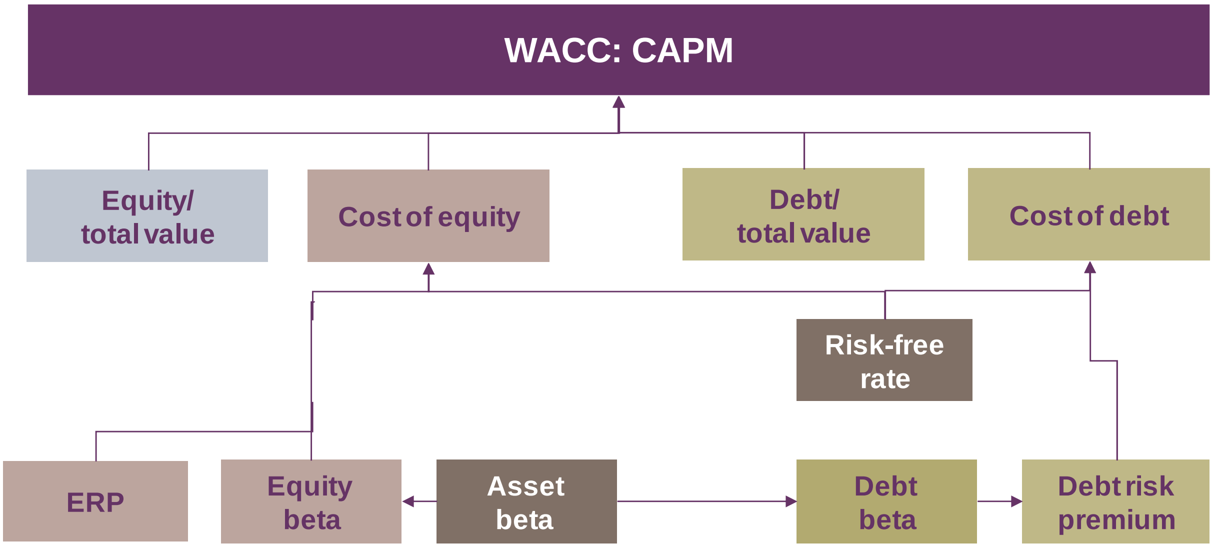
However, neither Fortis TCI nor TCU has assessed the value of its assets using the MEA value at any point during the period considered. A simplifying assumption is therefore to use book values as a proxy for the correct asset value to use in the profitability analysis on the basis of ROCE.

Cost of capital calculation framework

The framework adopted to calculate the WACC is the CAPM, as illustrated in Figure A1.1.

[147] See, for example, Mayer, C. (1988), 'The real value of companies accounts', *Fiscal Studies*, **9**, 1–17.
[148] See Edwards (1986), op. cit.; and Franks and Hodges (1996), op. cit.
[149] See, for example, OFT (2003), 'Assessing profitability in competition policy analysis', Economic Discussion Paper 6, p. 54.

Figure A1.1 WACC/CAPM framework



Source: Oxera.

This framework comprises a calculation of the cost of equity (the returns expected by equity investors) on the basis of:

– the risk-free rate, which measures the return required by investors from investing in a security that is judged to be relative risk-free (eg, government bonds yields);
– the equity beta, which measures the risk of the asset (eg, electricity companies in TCI) relative to the market as a whole;
– the ERP, which is the excess return on the market portfolio over the risk-free rate.

The cost of equity is therefore:

$$r_e = RFR + \beta \times ERP.$$

The cost of debt is calculated on the basis of the risk-free rate. The debt premium is specific to the company and is the difference between yields on the company's bond and the risk-free rate.

The cost of debt is therefore:

$$r_d = RFR + \text{debt premium}.$$

The ratio of net debt over a company's value (ie, financial gearing, or g) provides the basis for weighting the relative role of the cost of equity and debt in the calculation of the overall company's WACC.

Therefore:

$$WACC = (1 - g) \times r_e + g \times r_d.$$

Calculations are carried out taking the following into account:

– the cost of capital calculated using the assumptions described below is likely to change over the period in question and these changes need to be considered;

– allowed returns are assumed to be assessed for TCI companies using a mix of recent evidence (eg, yields on treasury bonds) and long-term evidence (eg, ERP) to assess the broad level of returns at the end of the year before the year for which the returns are assessed.

The following sections illustrate in more detail the assumptions for each component of the cost of capital.

A1.1 Cost of capital calculation—specific assumptions

A1.1.1 Risk-free rate

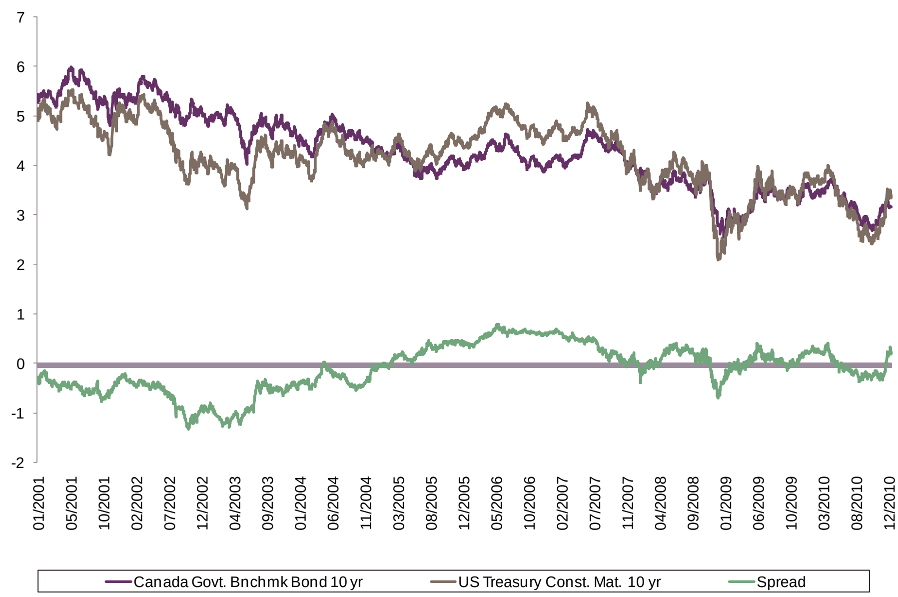
The risk-free rate is estimated on the basis of nominal US treasury government bonds with a ten-year maturity. The maturity used is consistent with an investor taking a medium- to long-term perspective when investing in TCI electricity companies.

The nominal value encapsulates the risk-free level of return that investors expect and their inflation expectations. Using the nominal value of the US treasury government bond is consistent with the perspective of an American investor whose objective is to achieve target returns in real terms in their home market (ie, the USA, as it would encapsulate the inflation expectation in the USA). This is appropriate for TCU's parent company (WRB Enterprises Inc). Fortis TCI is part of Fortis Inc. a Canadian group. Like the USA, over the period considered, Canada held a AAA rating, and as such its treasury bonds could be used to assess the risk-free rate.

Given the two candidate sources to assess the risk-free rate, the two bonds were compared over the period of analysis to see whether there were any persistent differences between the two bonds yields—for example, in inflation expectations held by investors—which would ultimately warrant the use of two risk-free rate sources according to which investors' perspectives would be chosen.

The comparison of yields on bonds with ten-year maturity (including the spread between the two yields calculated as US bond yields minus Canadian bond yields) over the period of analysis is shown in Figure A1.2.

Figure A1.2 Comparison of yields on ten-year constant maturity bonds for Canada and USA



Source: Oxera analysis; and Datastream.

Over the period considered, the average difference is minimal (10 basis points). However, the use of yields on US nominal bonds could have resulted in a return being allowed that was below a Canadian investor's expectations in the earlier period of the analysis, and then above expectation in the central part of the analysis (ie, 2005–07), and above/below expectations in the more recent years (where the mean spread for 2008–11 is zero).

On balance, the evidence on ten-year bonds would indicate that the use of yields on US bonds is adequate to address the expectation of risk-free returns for a North American investor seeking to maintain stable real returns in the home market.

A particular value for the risk-free rate can be chosen using long-term averaging (eg, one or more years), short-term averaging (eg, three to six months), or even spot values. Long-term averaging might result in a value that is not representative of rates for the year being analysed. The short-term average and, even more so, the spot values may be affected by few abnormally high or low values.

On balance, a spot value and/or short-term average value are more suitable to identify the level of risk-free rate for each year of the analysis.

The analysis has considered the spot value for US treasury bonds with a ten-year maturity at a cut-off point (ie, the end of the year before the year for which the WACC is being calculated). This value was then compared against a three-month average (three months before the cut-off date)—in other words, the comparison has been used to assess whether the spot value is abnormally high or low (see Table A1.2).

Table A1.2 Risk-free rate

Year	Spot value on cut-off date	Three-month average prior to cut-off date
2001	5.12	5.57
2002	5.07	4.76
2003	3.83	4.00
2004	4.27	4.29
2005	4.24	4.18
2006	4.39	4.49
2007	4.71	4.63
2008	4.04	4.27
2009	2.25	3.25
2010	3.85	3.47

Note: The cut-off date is taken as the date in the preceding year for which the last data point is available (eg, December 31st 2000 for 2001).
Source: Oxera analysis, and Datastream.

The above shows that spot values and the three-month average are broadly in line throughout the period, with the exception of 2009, when the three-month mean value exceeded the spot value by nearly 100 basis points.[150] The use of a three-month average is more appropriate as it reflects the levels observed throughout the year. Based on the historical values of the averages obtained, Oxera recommends an interval estimate of 3.5–4.5% for the risk-free rate.

Cost of equity

In addition to the assessment of the risk-free rate, the cost of equity requires an assessment of the beta and ERP. With regard to the former, as neither Fortis TCI nor TCU is a listed company, no beta is observable for them (although Fortis Inc, the parent company of Fortis TCI, is listed on the Toronto stock exchange). Thus, a beta needs to be elicited from comparator companies.

[150] A basis point is a hundredth of a percentage point (ie, 1/100th of 1%).

A1.1.2 Comparator selection

TCU and Fortis TCI have specific characteristics that are likely to make them different from most energy listed companies around the world. However, from the perspective of an international investor, most of these specific characteristics and related risks (ie, variability of returns) can be addressed by investing in a diversified portfolio. What matters from an investor perspective is a company's exposure to systemic risks (eg, the business cycle).

The comparators were therefore selected using a sifting criterion (ie, if companies were not listed or their stocks were not traded sufficiently frequently), a broad operating indicator (ie, companies were taken from the energy sector only), and a regulatory criterion. The criteria can be summarised as follows:

– **listing and liquidity**: the comparator company would be listed and the stock would be liquid (ie, traded on at least 90% of the trading days);

– **operating features**: operating profit and income primarily come from energy operations (electricity generation and/or transmission and/or distribution and/or retailing; gas production and/or transportation and/or distribution and/or retailing) throughout the period;

– **regulatory context**: for the energy activities subject to regulation, this would be akin to the cost of service approach.

Candidate comparators included:

– Caribbean utility companies, although only a few of these were listed and for their stock was not sufficiently liquid according to the criterion (ie, Caribbean Utilities Company (TSX), Jamaica Public Service Co. Ltd. (JPS), Dominica Electricity Services Ltd (ECSE), Grenada Electricity Services Ltd (ECSE), St Lucia Electricity Services Ltd (ECSE);

– listed electricity companies in other islands (eg, Jersey, Mauritius, Sri Lanka, Malta); however, only Jersey Electricity was listed and its stock was not sufficiently liquid according to the criterion.

The following tables list the companies selected as comparators and indicates the percentage revenues derived from the energy activities throughout the period.

Table A1.3 Comparator list, regulatory regime and parts of value chain regulated

Comparator	Regulatory regime	Vertical integration	Regulated business
Hawaiian Industries Inc.	Cost of service (ROE)	Fully integrated	Transmission, distribution and sale of electricity
Emera Inc.	Cost of service (ROE)	Fully integrated	Transmission, distribution and sale of electricity
NV Energy	Cost of service (ROE)	Fully integrated	Transmission, distribution and sale of electricity
American Electric Power	Cost of service (ROE)	Fully integrated	Transmission, distribution and sale of electricity
IDACorp	Cost of service (ROE)	Fully integrated	Transmission, distribution and sale of electricity
FirstEnergy Inc.	Cost of service (ROE)	Fully integrated	Transmission, distribution and sale of gas
North West Natural Gas	Cost of service (ROE)	Transmission and distribution	Transmission of natural gas
Piedmont Natural Gas	Cost of service (ROE)	Transmission and distribution	Transmission of natural gas

Note: Sale of electricity refers to wholesale electricity sales to other utilities, energy marketing companies and incorporated municipalities. Fully integrated means that the company is engaged in generation, transmission, distribution and sales of the utility.
Source: FERC website.

The nature of the business in Hawaii is similar to that in TCI on many fronts. In Hawaii, the electricity systems on each island are independent. Because there are no neighbouring utility companies from which to draw electricity in the event of a problem, they have reserve generating capacity and multiple distribution routes. This increased infrastructure is paid for by a small population. Furthermore, more than 50% of the electricity bill is made up of fuel costs, which is adjusted to accommodate changes in fuel prices.

Table A1.4 Contribution of energy revenues to total revenues of comparators (%)

Comparator	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Hawaiian Industries Inc.	75	76	78	81	81	83	83	89	88	89
Emera Inc.	91	93	90	90	96	97	95	96	95	92
NV Energy	100	100	100	100	100	100	100	100	100	100
American Electric Power	97	93	95	97	92	96	90	92	94	95
IDACorp	100	100	100	100	100	100	100	100	100	100
FirstEnergy Inc.	100	100	100	100	100	100	100	100	100	100
North West Natural Gas	100	100	100	100	100	100	100	100	100	100
Piedmont Natural Gas	100	100	100	100	100	100	100	100	100	100

Note: Hawaiian Industries Inc. is the only company with a non-utility business (banking). Emera Inc. and AEP have revenue from other sources, which is subtracted.
Source: SEC10-K filings; Annual reports

It is important to stress that the scale of operations of the comparators and that of the TCI electricity companies is very different. Table A1.5 shows the number of customers for the electricity and or gas operations of the comparators for 2009, as an example.

Table A1.5 Customer base of comparators, 2009

Comparator	2009
Hawaiian Industries Inc.	442,584
Emera Inc.	601,782
NV Energy	2,126,734
American Electric Power	4,248,114
IDACorp.	488,175
FirstEnergy Inc.	4,498,000
North West Natural Gas	665,068
Piedmont Natural Gas	952,469
TCU	1,934
Fortis TCI	10,745

Note: NV Energy was Sierra Pacific Resources prior to 2008.
Source: SEC10-K filings; Annual reports; CARILEC (2009), 'Benchmark study of Caribbean utilities'.

The scale of operations might have an impact on the level of systemic risk to which a company such as Fortis TCI or TCU and their comparators is exposed. Indeed, the customer base of Fortis TCI and of TCU is much smaller than those of the comparators, and, in the context of an economy heavily reliant on tourism as a source of income,[151] makes it likely that any downturn in the world economy would have an acute impact on the demand for electricity. This is likely to be more so than for the comparators, which may have a more diversified customer base in terms of exposure to economy downturns. This needs to be considered when using the cost of capital estimates to infer the reasonable or otherwise of historical returns.

Equity and asset betas

The estimates of beta in the WACC calculations are based on ten-year weekly beta estimates of the comparators. Table A1.6 reports the equity beta for the comparators over the period under consideration as elicited (raw beta or β_r) and adjusted using the Blume adjustment (β_a).[152] The equity beta, raw and adjusted, is then adjusted to net the beta estimate of any impact of the capital structure (ie, the mix of debt and equity finance) on the company's beta—ie, to remove the impact of financial risk related to a specific capital structure. This is done using a procedure known as the Miller formula, which elicits the beta related to the asset.[153]

[151] The hotel industry contributed nearly 25% of TCI GDP in 2010.

[152] The equity beta is the coefficient of the explanatory variable in the linear regression of returns of the stock for which the beta is being calculated (dependent variable) and the market returns (explanatory variable); this is the raw beta. This approach can bias downwards the estimates (ie, stocks are predicted to do systematically worse than they actually do compared with the market), and an adjustment to the estimation of the beta has been proposed; namely, the Blume adjustment, which calculates the β_a as 1/3*1 + 2/3* β_r

[153] The Miller adjustment is $\beta_{asset}=(1 - g) \times \beta_{equity}+g \times \beta_{debt}$, Oxera has assumed that β_{debt} is equal to zero, and therefore the asset beta is simply $\beta_{asset}=(1 - g) \times \beta_{equity}$.

Table A1.6 Raw and adjusted asset betas for the comparators, 2001–10

Comparator	Raw asset beta	Adjusted asset beta
Hawaiian Industries Inc.	0.21	0.28
Emera Inc.	0.20	0.31
NV Energy	0.28	0.29
American Electric Power	0.33	0.39
IDACorp	0.33	0.40
FirstEnergy Inc.	0.29	0.37
North West Natural Gas	0.32	0.41
Piedmont Natural Gas	0.40	0.49

Note: NV Energy was Sierra Pacific Resources prior to 2008.
Source: Oxera analysis and Datastream

For the purpose of calculating the WACC, an interval between 0.3 and 0.4 for the period 2001–10 was chosen, consistent with the range of asset beta values obtained for the period.

ERP

The ERP can be estimated in a number of ways, as shown in the box below.

Box A.2 Approaches to estimating the ERP

Broadly, there are three approaches to estimating the ERP.

– **Ex post (realised) premium**—this measures the returns earned in the past on equities relative to risk-free securities. This approach implicitly assumes that investors' expectations are based on past returns. This approach has the advantage of being widely understood, and relies on measurable data.

– **Ex ante (implied) premium**—this uses information on future cash flows to investors (such as dividends, earnings, or overall economic productivity) to estimate the ERP implied by the price of traded assets today.

– **Ex ante (stated) premium**—this involves surveying sub-sets of investors and managers to obtain their views on expectations about equity returns in the future.

In practice, regulators typically use both ex ante and ex post approaches to estimate the ERP, although they typically place less weight on surveys.

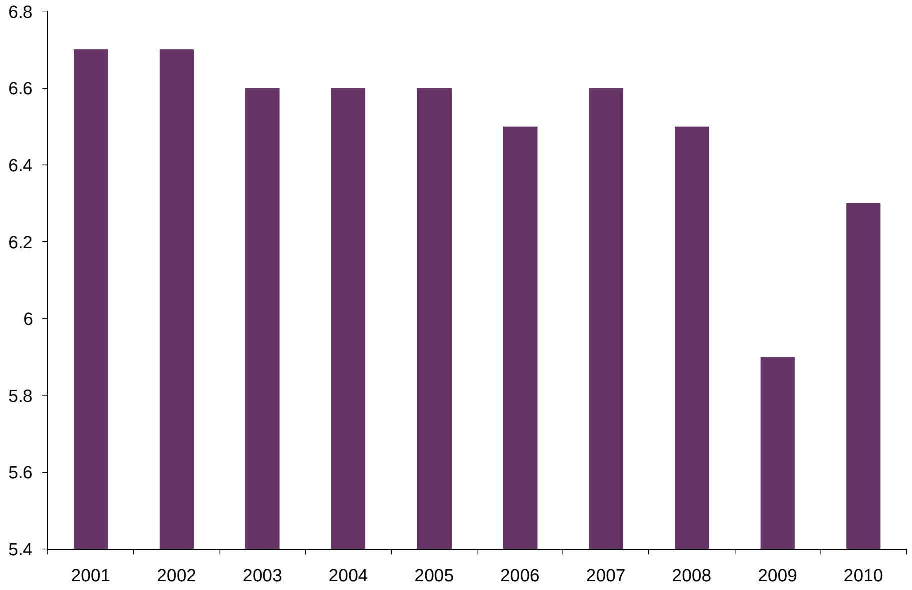
In the context of the simplified approach to the assessment of the historical performance, the ERP is estimated using an ex post approach. The long-term average equity premium is compared with US treasury bonds on the US stock market starting in 1900 until the year before the year for which the WACC is being calculated (eg, for 2005, the ERP estimate is the average return between 1900 and 2004).

In terms of the average value used, the arithmetic (as opposed to the geometric) mean is used. In the context of this analysis, this seems to be the most appropriate averaging approach.[154]

The ERP estimates for the period of the analysis are reported in Figure A1.3.

[154] Damodaran (2011) argues that if 'annual returns are uncorrelated over time, and our objective was to estimate equity risk premium for the next year, the arithmetic average is the best and most unbiased estimate of the premium.' Damodaran (2011), *Equity risk premium: determinants, estimation, and implications*, 2011 Edition, pp. 23–24.

Figure A1.3 Equity risk premium, 2001–10 (%)



Note: The ERP value for 2001 was not available. For simplicity, the 2002 value has been assumed as the value for 2001.
Source: Dimson, E., Marsh, P. and Staunton, M. 'Global Investment Returns Yearbook', years 2002–10.

For the purpose of calculating the WACC, an interval between6% and 6.5% for the period 2001–10 was chosen. This is consistent with the range of long-term values obtained for the period.

Cost of debt

In addition to the RFR, of which the calculation is illustrated in the previous sections, the cost of debt requires calculating the debt premium. This entails two steps: (i) establishing the credit rating of debt issuance by TCI electricity companies and (ii) assess the level of premium over the RFR for that rating.

A1.1.3 Establishing the rating of TCI electricity companies debt issuance

The comparators used for assessing the asset beta were used to assess an industry credit rating that would be applicable to either Fortis TCI or TCU when issuing new debt.

The rating (s) for bond issuance over the period for the comparators, when applicable, is reported in Table A1.7.

Table A1.7 Comparator bond issuance rating

Comparator	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Hawaiian Industries Inc.	(BBB+)	-	(BBB+)	BBB	-	BBB	-	-	-	-
Emera Inc.	-	-	-	-	(BBB+)	-	-	(BBB+)	BBB	BBB
NV Energy	-	-	-	(B-)	(B-)	-	-	-	-	BB
American Electric Power	(A- /BBB+)	-	BBB	-	-	-	-	BBB	-	-
IDACorp	A+	A-	A-	A-	BBB+	-	BBB+	BBB	BBB	BBB
FirstEnergy Inc.	BBB	-	-	-	-	-	-	-	BBB	-
North West Natural Gas	-	A	A	-	A+	AA-	-	-	AA-	-
Piedmont Natural Gas	A	-	A	-	-	A	-	-	-	-

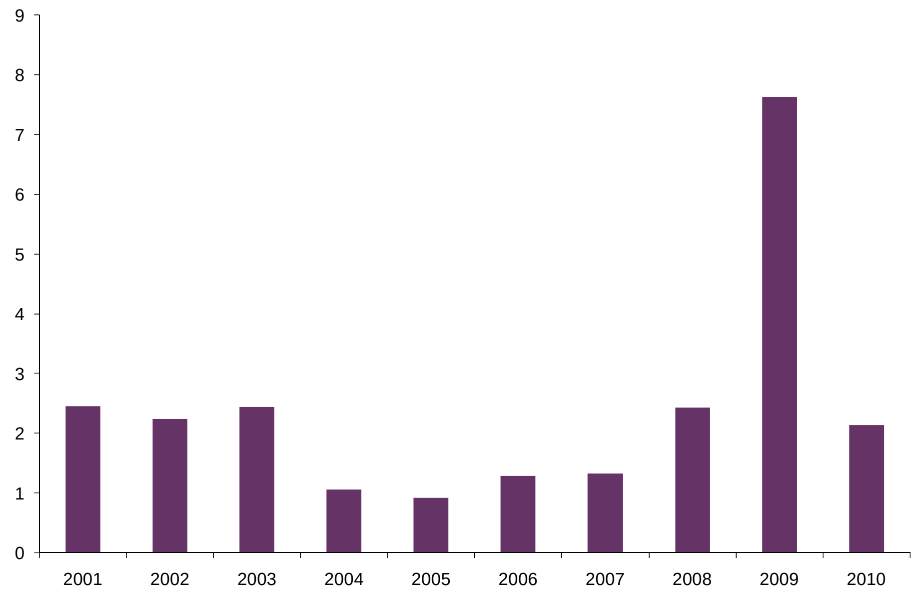
Note: All figures in brackets () are bond ratings of wholly owned subsidiary companies involved in the energy business. Bond ratings for NV Energy prior to 2008 are for Sierra Pacific Resources. All ratings are S&P ratings effective at launch date of issue.
Source: Dealogic DCM Analytics

While the rating varies across companies and across time, the predominant rating seems to be BBB, and this could be therefore assumed to be a reasonable industry debt rating level. It is worth noting that BBB is an investment grade rating often used by regulators to assess the level of financeability of their regulatory decisions, a choice of an industry BBB debt rating would be consistent with regulatory practice when establishing financeable regulatory decision.

A1.1.4 Debt premium for the comparators/industry credit rating

The BBB corporate bond yields compared with the 7–10-year maturity US Government bonds for the spot day on which RFR is measured allows eliciting the debt premium. The debt premium estimates for the period of the analysis are reported in Figure A1.4.

Figure A1.4 Debt premium, 2001–10 (%)



Note: The Debt premium is calculated as an average value of the daily spot premium for three months prior to the year under consideration.
Source: Oxera analysis and Datastream.

As demonstrated above, in 2009, the debt premium was unusually high. This is attributed to the global financial crisis when yields on sovereign debt were highly depressed as a result of a 'flight to safety' and the risk inherent in corporate bonds was perceived as high. The opposite is observed in 2005. Economically, this can be explained by investor tendency to seek riskier investments in times of economic prosperity. The resultant lack of demand for treasury securities and increased demand for corporate bonds offering better returns leads to a narrowing of the debt premium.

For the purpose of calculating the WACC, an interval estimate of 1.5–2% is considered appropriate and reflective of the debt premium prevalent during the period under consideration.

WACC calculations

The previous sections provide all the components that are used in the WACC calculation, with the exception of an explanation of the capital structure—ie, the relative weights of equity and debt finance built into the financing of the assets of TCU and Fortis TCI: the financial gearing.

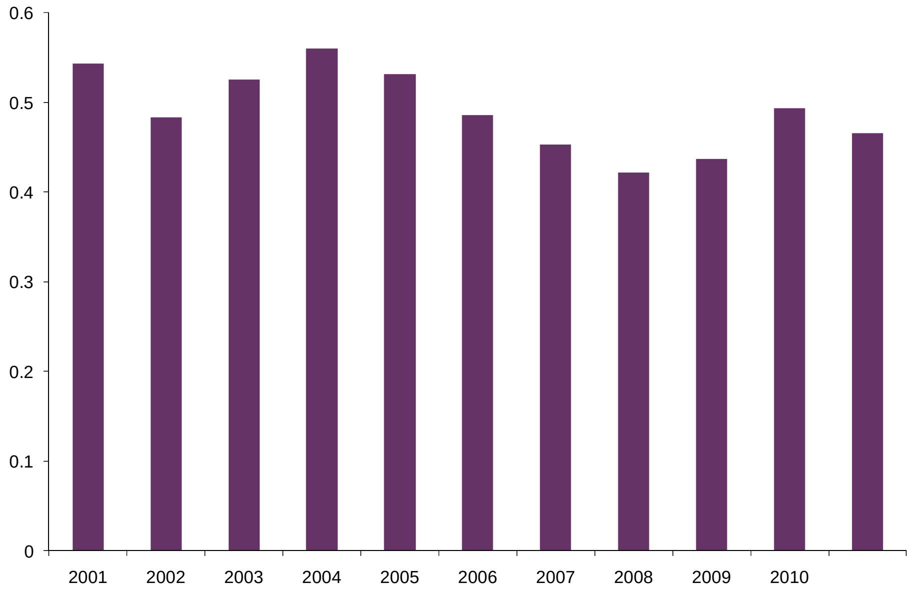
Financial gearing

An industry/comparator's financial gearing is used, calculated as the ratio of net debt (ie, long- and short-term debt net of cash and cash equivalents) over the sum of net debt and equity market value (ie, the market value of all outstanding shares at one point during the year—usually the year-end).

Gearing levels used in the WACC calculation are, for each year, those of the preceding year (eg, the 2005 gearing is calculated using the 2004 net debt and equity market value).

The gearing levels calculated are reported in Figure A1.5.

Figure A1.5 Average gearing level across all comparators



Source: Oxera analysis and Datastream.

The average level of gearing over the period is just below 50%, which is consistent with the gearing levels of Fortis TCI, calculated on a book-value basis, as opposed to the market value approach underpinning the results in Figure A1.5, but higher than TCU, which, in 2010, had close to nil gearing (ie, it is fully financed using equity or short-term debt).

For the purpose of calculating the WACC, the average gearing levels over the period 2001–10 for each of the comparators was calculated using the arithmetic average of the annual gearing levels. The gearing levels obtained were then averaged across all comparators, yielding a point estimate of 49% gearing.

A2 Regulation and resourcing issues in the Caribbean

Regulatory institution design and effectiveness in Caribbean countries has been assessed by The World Bank and representatives of regional regulatory bodies. They have highlighted the importance of ensuring the independence, transparency and accountability of the regulators. Much of the ability of the regulators to maintain these requirements is in turn dependent on their ability of hire, train and retain effective staff.

This appendix presents the principles underlying effective regulatory governance, drawing lessons from regulatory experience across the Caribbean. However, some of the literature explored refers to the situation a few years ago, and may have been overtaken by more recent developments.

Requirements for effective regulatory governance

The World Bank has reviewed the governance of regulatory agencies across Latin America and the Caribbean, indicating that the required characteristics of a regulator are as follows:

- autonomy from political authorities and autonomy of management and regulatory competencies;
- transparency before institutional and non-institutional stakeholders;
- degree of accountability to the three branches of government (executive, legislature and judiciary); and
- tools and capacities for carrying out regulatory activities and the improvement of its institutional development.

More detail on each of these characteristics is given in Box A2.1.

Box A2.1 World Bank recommendations on governance of regulatory agencies

The World Bank has presented the following recommendations on good practice in the governance of the regulatory agencies.

- **Autonomy**—procedures and mechanisms for ensuring the political, managerial and regulatory independence of the agency.

  - **Political autonomy** refers to independence of the regulatory agency's decision-making from ministers and bodies in charge of policy-making. In the absence of political independence, regulators may compromise the long-term operations of the sector (eg, sufficient investment) in favour of short-term political interests (eg, low tariffs). Political autonomy requires independent processes for selecting the regulatory agency's directors and renewal of directors' mandates. In addition, the regulatory agency's budget should be independently determined—for instance, through a regulatory tax—instead of being part of wider government funds.

  - **Managerial autonomy** involves the freedom of a regulatory agency to determine the use of its budget and the organisation of its resources. Managerial autonomy is driven by factors such as the ability of the agency to determine its own organisational structure; freedom to make its own decisions on personnel; financial autonomy to determine its own expenses; tools to improve its management, such as the provision of performance-based payments for its employees.

  - **Regulatory autonomy** relates to the nature of the regulatory agency's powers. Greater autonomy would be provided if regulation were carried out by a separate agency than by the Parliament or the Executive. Also important are the nature of the agency's powers—consultative, oversight, pricing or rule-making. Furthermore, autonomy is also function of the extent of the regulatory agency's responsibilities to make decisions on issues of tariffs, service quality, consumer complaints, companies' investment plans, anti-competitive behaviour, and technical standards. In addition to holding these responsibilities, regulatory agencies should have the power to enforce their decisions.

- **Transparency**
  - **Social transparency**—factors that enhance social transparency include procedures to guarantee the disclosure and publication of relevant regulatory and institutional information; the participation of stakeholders in the regulator's decision-making process; publication by the agency of its decisions; the existence of a website or other tools to disseminate information; and the existence of advisory committees that play a role in the regulator's decision-making by representing different group interests.
  - **Institutional transparency** refers to transparency with respect to matters that do not relate to stakeholder involvement. More specifically, it relates to the application of rules to ensure the integrity and behaviour of the regulatory agency's officers. This can be achieved through collective decision-making by a board of directors with varied technical backgrounds; the publication of annual accounts; a record of board meetings; the use of publicly open processes to hire employees; and quarantine rules for directors that leave the regulatory agency.
- **Accountability**
  - The World Bank considers that a stronger degree of controls by the Executive than the Legislative branch of government could affect the autonomy of the regulator.
- **Regulatory, management and institutional tools**
  - **Regulatory tools**—instruments related to the conduct of regulatory policies through mechanisms, such as the use of benchmarking, rules-based methodologies for tariff revision, and the existence of instruments that regulate consumers' rights.
  - **Institutional tools**—effective regulatory governance requires the existence of instruments that improve the development of the regulatory agency's management and decisions. This can be achieved through mechanisms such as public consultations; the structure of posts and salaries; performance-based salaries for employees; mechanisms to register consumer complaints; and employee training.

The World Bank adds that, in reviewing a regulatory regime, it is necessary to consider both the formal aspects of the regime and its implementation.

Source: World Bank (2007), 'Assessing the Governance of Electricity Regulatory Agencies in the Latin American and Caribbean Region: A Benchmarking Analysis', Policy Research Working Paper 4380, November.

Effectiveness of regulators in selected Caribbean countries

The World Bank reviewed the regulatory regimes across Caribbean countries in 2005, highlighting the positive and negative characteristics of the regimes in individual countries.[155] In a number of cases, the governance criteria set out in Box A2.1 above had not been met, resulting in the ineffectiveness of the regulatory regimes.

The World Bank 2005 report stated that the regulatory regime in Jamaica had a number of positive features:

- in Jamaica, the Office of Utilities Regulation is a multi-sector regulator that oversees the electricity, transportation, telecommunications and water sector;

[155] World Bank (2005), 'Institutions, Performance, and the Financing of Infrastructure Services in the Caribbean', Working Paper No. 58.

- tariffs are set using a price cap approach on a five-year basis, being periodically adjusted to reflect changes in inflation and exchange rates;

- there is an automatic fuel cost adjustment with a lower limit on efficiency of generation plant. Likewise, a ceiling is placed on system energy in order losses to incentivise efficiency. The fuel efficiency rate and energy loss ceiling are also subject to regular review by the regulator to ensure that optimal efficiency incentives remain.

However, the report also highlights deficiencies in the regulatory regimes in a number of countries, providing recommendations on dealing with these:

- Trinidad & Tobago—like Jamaica, Trinidad & Tobago has a multi-utility regulator; however, personnel resource constraints prevent its effective operation;

- Dominican Republic—the energy sector needs to gain independence from executive power;

- Guyana—legal, personnel and financial constraints limit the effectiveness of the regulator;

- Dominica and Saint Lucia—although utilities are regulated by licence, there are no institutions to regularly monitor enforcement of licence conditions. Furthermore, the licences are poorly designed. For example, they commonly do not include target heat rates in the fuel surcharge, implying that costs arising due to inefficient generation are passed through in tariffs. Limits on heat rates would provide incentives for efficiency improvements, reducing the fuel input required per unit of output.

The report adds that a regulatory agency that sets tariffs and determines required service levels is not a necessity. Instead, tariffs can be set through long-term contracts and concessions that define the rules for setting and adjusting tariffs, alongside the obligations of the contract or concession-holders. However, an independent body that oversees the implementation of these rules and obligations would still be required.

Implications for human resource requirements

As noted above, The World Bank has pointed towards constraints in relation to the availability of skilled personnel on the inability of regulators to carry out their activities in a number of jurisdictions.

Staff with a range of technical skills are required by regulatory bodies to operate effectively.[156] These include economists, lawyers, accountants, financial analysts and engineers, who would require technical knowledge in their fields as well as the ability to apply this in a regulatory context.

- In the absence of such a knowledge base, regulators may face the risk of being dominated by utilities that have superior understanding of regulatory issues and their implications.

- Regulators would be expected to obtain operational information from utilities. However, regulators with insufficient technical competence may ask utilities for too little information about their operations, being unable to evaluate the quality of information provided. Alternatively, they may ask for too much information, but not have the capabilities to evaluate it.

[156] Downes, A.S. and Husbands, A. (2004), 'Human Resource Systems for Regulatory Institutions: An Imperative for the Caribbean', January.

In addition to technical staff, the research and investigative functions of a regulator need to be supported by a range of staff, including librarians/information specialists, customer service/complaints officers, policy analysts, and statistical officers.

Table A2.1 gives examples of the wide range of staff employed by regulators in selected Caribbean countries, and highlights that multi-utility regulators have been put in place in a number of countries.

Table A2.1 Professional staff in selected Caribbean regulatory agencies (at September 2003)

Territory	Regulator	Sectors regulated	No. by profession
Barbados	Fair Trading Commission	Telecommunications Electricity Competition Consumer protection	Economist (1) Financial analyst (1) Lawyers (2) Accountants (2) Research officer (1) Research assistant (1) Director of utility regulation (1) Electricity analyst (1) Telecoms analyst (1)
Belize	Public Utilities Commission	Telecommunications Water/waste Electricity	Specialist senior managers (3) Generalist—monitoring and compliance (1) Outsource—legal and economics consultants
Jamaica	Office of Utility Regulation	Electricity Telecommunications Public passenger transport by road, rail and ferry Water Sewerage services	Director analysis and research (1) Legal (3) Financial comptroller (1) Economist (6) Numbering administrator (1)
Trinidad and Tobago	Regulated Industries Commission	Water and sewerage authority Electricity Telecommunications Power generation InnCogen Limited (electricity)	Assistant executive director—economics and research (1) Tariff analysts (2) Legal/corporate secretary (1) Chief financial officer (1) Utility accountants (1) Accounts officer (1)

Source: Downes and Husbands (2004), op. cit.

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