Connection and Transmission Use of System Charge Methodology:

Consultation Paper (01/2018)

هيئة تنظيم الكهرباء - عمان

AUTHORITY FOR ELECTRICITY REGULATION, OMAN

Attachment to the Authority's letter dated 18 January 2018

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Glossary

AEMO	Australian Energy Market Operator
BUoS	Balancing Use of System
CAPEX	Capital expenditure
CO_2	Carbon dioxide
CRU	Commission for Regulation of Utilities
CUSC	Connection and Use of System Charges
DG	Distributed generation
DSM	Demand side management
ENTSO-E	European Network of Transmission System Operators (electricity)
FTR	Financial Transmission Rights
GAV	Gross Asset Value
KV	Kilovolt
KW	Kilowatt
KWh	Kilowatt hour
MAR	Maximum Allowable Revenue
MIS	Main Interconnected System
MTSD	Maximum Transmission System Demand
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
O&M	Operation and Maintenance
OETC	Oman Electricity Transmission Company
Ofgem	Office of Gas and Electricity Markets
OPEX	Operating expenditure

OPWP	Oman Power and Water Procurement Company
OR	Omani Rials
PDO	Petroleum Development Oman LLC
PJM	Pennsylvania New Jersey Maryland
PPA	Power Purchase Agreement
RAEC	Rural Areas Electricity Company
RUT	Regulated Units Transmitted
SEM	Single Electricity Market
SONI	System Operator Northern Ireland
ToU	Time of Use
TRC	Transmission Running Charge
TUoS	Transmission Use of System
WACC	Weighted Average Cost of Capital

1. Introduction

1.1 This document discusses a range of issues related to evolution of the Transmission Connection and Use of System Charges (CUSC) methodology.

1.2 The CUSC methodology sets the rules through which the Oman Electricity Transmission Company (OETC) recoups the costs of financing, building and operating the electricity transmission system for the Main Interconnected System (MIS) and the Dhofar Power System.[1] These costs are comprised of connection charges (i.e., the capital and operating costs of a connection to the transmission network) that are paid by generators and transmission-connected customers and Use of System charges (i.e., the capital and operating costs of the transmission system) that are paid by licensed suppliers.

1.3 Based on the CUSC methodology, OETC publishes annually a Statement of Transmission System Charges that sets out the Transmission Use of System (TUoS) and connection application fees that will apply for the following year.[2] The same charges apply to both the MIS and the Dhofar systems.

1.4 Transmission charging plays an important role in the efficient operation of the electricity system. In addition to facilitating the recovery of the costs of investment and operation of transmission infrastructure, charges can also provide signals for investment requirements in generation and transmission and, to the extent that the charges are reflected in end-user tariffs, can also encourage more efficient electricity consumption behaviour.

1.5 The transmission charging methodology can also influence the decisions of transmission-connected electricity-intensive businesses about where to locate their activities. Further, to the extent that these activities are internationally mobile, the transmission charging methodology will affect the attractiveness of Oman as a place to do business.

1.6 Other than a small refinement that took effect at the beginning of 2016, the current charging methodology has been in place since 2005.[3] As such, the Authority believes

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[1] In other areas, transmission services are provided by the vertically integrated Rural Areas Electricity Company (RAEC).

[2] The Statement of Transmission System Charges for 2018 can be found at: http://www.aer-oman.org/aer/NetworkCharges.jsp?heading=2

[3] The previous revision to the CUSC methodology altered the way in which OETC recouped the cost connection Operation and Maintenance (O&M) costs from generators and transmission-connected entities.

that it is prudent to revisit the CUSC methodology in order to assess whether it remains fit for purpose both for the requirements of the current electricity system and for the changes that either underway or anticipated over the short to medium term. These include:

- The expected introduction of the spot market for electricity expected to go-live in 2020), which will impact on the way in which electricity is procured and dispatched;
- Changes in the way in which electricity is produced and consumed as a result of greater penetration of renewable energy, distributed generation (DG) and demand-side management (DSM). This will impact on the demand for transmission services both in terms of connections and system usage;
- Large electricity consumers (defined as consuming over 150 megawatt hours (MWh) per year) face cost-reflective tariffs for electricity. This includes a transmission time of use (ToU) component that reflects a customer's contribution to peak demand. It is expected that the application of cost-reflective tariffs will be broadened to include other groups of consumers in the coming years; and
- Possible new interconnection capacity: OPWP is exploring the possibility of a new 400 KV interconnection between Nizwa, Duqm, Petroleum Development Oman LLC (PDO) and the Dhofar power system. OPWP, OETC and PDO are currently working to evaluate the benefits of increased interconnection, which could include fuel savings due to improved dispatch coordination between generators, access to areas with renewable energy potential and sharing of spinning reserves.[4]

1.7 This document discusses a number of issues that will inform how the CUSC methodology will operate in future and sets out a number of questions on these issues. The Authority invites interested parties to respond to this Consultation Paper by 18 March 2018. Responses to this document will inform the Authority's Initial Proposals for a revised CUSC methodology.

1.8 In parallel to the review of the CUSC methodology, the Authority is also consulting on the price control for OETC (TD-PCR5), which will set the allowable revenues for OETC from 2019. While these are distinct consultations, there are links between the price control and the CUSC methodology. These are explored further in Section 4.

[4] OPWP Seven Year Statement 2017-23, Issue 11.

Scope and structure of this consultation paper

1.9 Recognizing the range of objectives and issues to be addressed in revising the methodology (and the fact that the existing methodology has been in place in its current form for a number of years), this consultation document is structured as follows:

- Section 2 briefly describes the existing CUSC methodology focusing on the way in which charges are calculated;
- Section 3 discusses the objectives of the CUSC methodology and sets out a number of principles of regulatory best-practice that can be used to assess the desirability of possible changes to the methodology;
- Section 4 sets out some issues with the existing methodology (i.e., areas where it may not be fully aligned with the principles and objectives set out in Section 3) and provides a comparison with examples of connection and use of system charging arrangements in other jurisdictions;
- Section 5 sets out some possible options for reform of the CUSC methodology; and
- Section 6 sets out the timetable for this consultation and for any reforms to take effect.

2. Overview of the CUSC methodology

2.1 In this section, we describe the key aspects of the existing connection and transmission use of system charging arrangements. The full methodology is set out in the Connection and Use of System Charge Methodology Statement (also known as the "Condition 25 Statement"), which is developed by OETC.[5]

The statutory basis for transmission charging in Oman

2.2 The CUSC methodology is prepared in accordance with Condition 25 of the Transmission and Dispatch License and is approved by the Authority. OETC apply the CUSC to develop an annual charging statement that is published in December of each year, that provide the details of the connection and use of system charges that will apply in the subsequent calendar year.

2.3 OETC has a statutory obligation in respect of connection and use of system charges that are rooted in:

- The Law for the Regulation and Privatisation of the Electricity and Related Water Sector ("the Sector Law") promulgated by Royal Decree (78/2004); and
- The Transmission Licence issued by the Authority.

2.4 The Sector Law sets out the functions and objectives of licensed transmission system operators, which include requirements to:

- Finance, operate and maintain its transmission system in an effective and economic manner. This relates to the requirement for OETC to make efficient investments and run the transmission system in a manner that ensures safe and reliable services and limits cost increases for current and future consumers;
- Offer non-discriminatory terms for connection to and use of the transmission system. In the context of electricity transmission, the concept of 'non-discrimination' means that OETC should only offer materially different terms to different types of customers where those differences can be objectively justified (e.g., as a result of the different demands that different customers place on the system); and

[5] See: www.omangrid.com%2Fen%2FReport%2FConnection%2520and%2520Use%2520of%2520System%2520Charge%2520Methodology.PDF&usg=AOvVaw1ZPMDMXcw9qnIgZkOz4OMw

- Charge a cost-reflective tariff to persons whose production facilities or systems are connected to the transmission system and to licensed suppliers and the Oman Power and Water Procurement Company (OPWP) for use of the system.

2.5 The Transmission and Dispatch Licence places obligations on OETC with respect to connection and use of the transmission system. Specifically:

- **Connection**: OETC has an obligation to offer terms for connection to any person who applies and to provide details of the type of connection that the person should obtain. Connection charges cover the capital costs of connection assets, any ancillary items (e.g., common buildings that house the connection assets and other assets) and the on-going cost of maintaining the connection. Connection charges are based on the principle of 'shallow charging'. This means that an entity requesting a connection is required to pay the cost of that connection but not the costs associated with any wider network extension or reinforcement that is required to support the connection. Instead, these wider costs are recovered from licensed suppliers through the use of system charges.
- **Use of system**: OETC has a duty to accept into the transmission system electricity provided by OPWP or a licensed supplier and to deliver such quantities of electricity at such exit points on the transmission system as is required by OPWP or a licensed supplier. The use of system charges are paid by licensed suppliers and cover the investment, operation and maintenance costs of the transmission system.

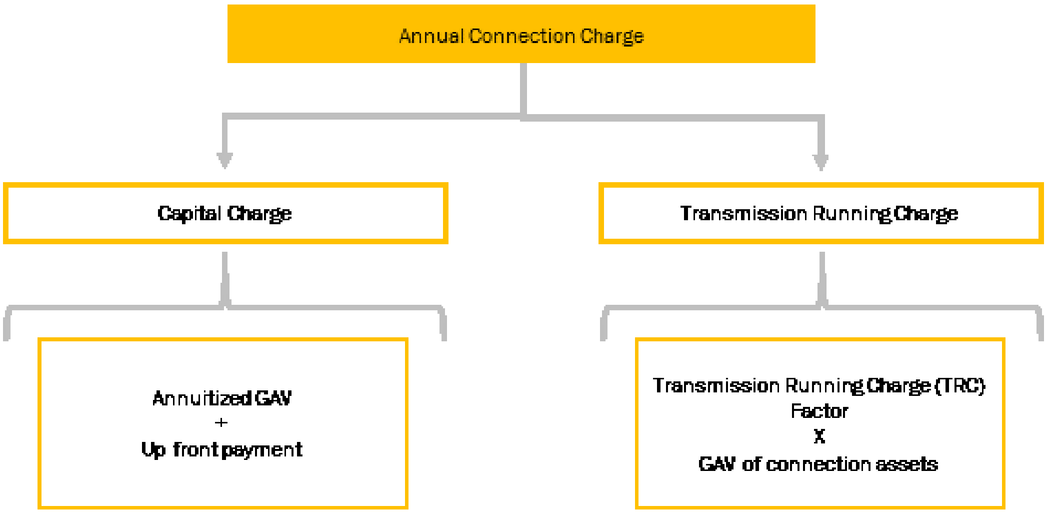
Connection charging methodology

2.6 Connection charges cover the costs of 'Connection Assets' (which are defined as the assets solely required to connect an individual user to the transmission system and would not normally be used by another party), any ancillary items (e.g., common buildings that house the connection assets and other assets) as well as covering the on-going costs of maintaining the connection.[6] The connection charges apply to all parties connected to the transmission system, which includes electricity generators and transmission-connected consumers.

2.7 The annual connection charge is composed of two elements: (a) capital charge; and (b) transmission running charge (TRC), as is shown in Figure 1.

[6] Connection and Use of System Charge Methodology Statement, Section 2 (Charging Principles).

Figure 1: components of the annual connection charge



2.8 The capital charge component recovers the capital cost of providing the connection assets. The capital charge is based on the Gross Asset Value (GAV) of the connection assets (which represents the capital element of the actual costs of providing the asset, including the costs of purchase, transport, installation, financing, design and consents) annuitized over the weighted average asset lifetime. The annuitized value includes a rate of return based on the weighted average cost of capital (WACC), set through OETC's price control process. The capital charge is based on the following formula (reproduced from the CUSC[7]):

$$\text{Capital charge} = (\text{GAV} \times \text{WACC}) / 1 - (1 + \text{WACC})^{-N}$$

Where:

GAV = gross asset value
WACC = weighted average cost of capital
N = weighted average asset lifetime

2.9 In addition, connecting entities have the opportunity to make an up-front capital contribution through the Capital Charge Payment Option. Any up-front capital contribution is deducted from the GAV in the calculation of the annual capital charge. In the situation where the connecting entity pays the capital costs up-front in full, the annual capital charge will be zero.

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[7] Connection and Use of System Charge Methodology (p.19)

2.10 The TRC component of the annual connection charge recovers the costs of operation and maintenance of the connection assets. Some entities are responsible for the operation and maintenance of their connection asset (so-called 'user maintained assets'). As such, no TRC is charged to these entities.

2.11 For all other entities, the TRC is calculated through an annual 'TRC factor', which is based on the inflation-adjusted connection asset operating expenditure allowance (which is set in OETC's price control review) as a proportion of the total connection asset GAV (excluding user maintained connection assets). The TRC factor is calculated through the following formula:

TRC Factor = Connection Asset Operating Expenditure Allowance (inflation adjusted) / (Connection Asset GAV – User Maintained Connection Asset GAV)

The TRC factor will therefore vary from year-to-year depending on the evolution of operating costs and connection capex.[8] The TRC for a particular entity is then calculated by multiplying the TRC factor by that entity's GAV. The TRC is calculated through the following formula:

TRC for customer A = TRC factor x (customer A's connection asset GAV – customer A's user maintained connection asset GAV)

2.12 The CUSC methodology also describes how to calculate the connection charges in the situation where multiple entities are connected to a particular connection asset as well as for connection modifications, temporary connections and terminating connections.

Transmission use of system charging

2.13 Transmission Use of System Charges are paid by licensed suppliers ("TUoS") charges recover the investment, operation and maintenance costs of the transmission network. The same TUoS charges apply in both MIS and Dhofar.

2.14 The Maximum Allowable Revenue (MAR) that OETC is permitted to collect for these activities is set by the Authority at periodic price control reviews. The MAR is allocated

[8] For example, during the previous price control the TRC was factor was 3.13% in 2013, 2.83% in 2014 and 2.19% in 2015. The falling TRC factor was driven largely by an increase in connection capex.

to licensed suppliers based on their shares of maximum system demand measured in megawatts (MW), which is expected to occur during the summer months. The Maximum Transmission System Demand (MTSD) refers to "the maximum average electricity demand in an hour as metered or otherwise measured at exit points on the Transmission System in relevant year t".[9]

2.15 This means the transmission charge for an individual supplier is determined entirely by that supplier's customers' consumption during the peak hour in the year.

2.16 For each year, OETC estimate the MAR for the coming year (based on the revenue drivers of maximum system demand and total units transmitted). OETC will deduct from the MAR any other regulated income earned in order to estimate the residual amount that will need to be recouped through the TUoS charges. The residual amount of money is then divided by the forecast MTSD for the coming year to get a TUoS charge expressed in Oman Rials (OR) per MW. This TUoS tariff is published by OETC in December of each year for the following year.

2.17 OETC invoices licensed suppliers based on an expectation of their contribution to maximum transmission system demand. That is, if it is expected that a licensed supplier will account for 20% of maximum transmission system demand, it will be required to pay 20% of the MAR (minus other regulated income). This means that suppliers face a share of the costs that are aligned with the burden that they are placing on the transmission system at system peak. The TUoS charges for a particular licensed supplier is therefore calculated by the following formula:

> Annual TUoS charge for supplier A = (OR/MW) x maximum transmission system demand of supplier A (MW)

2.18 2OETC revisits these calculations at the end of the year (once maximum system demand is known) to reflect each suppliers actual/outturn contribution to the system and will make any required adjustments to the amounts paid by suppliers. By way of illustration, the contribution of each of the distribution companies to maximum system demand in 2016, and the associated TUoS charges, are shown in Table 1.

[9] Connection and Use of System Charge Methodology Statement, Section 3 (Connection Charges).

Table 1: supplier contributions to TUoS charges (2016)

	MTSD (MW)	TUoS charges (RO million)
MEDC	2,225	27.5
Mazoon	1,964	24.3
Majan	1,518	18.8
Dhofar	499	6.2

Source: OETC

3. Objectives and principles of connection and transmission charges

3.1 Connection and use of system charges should be designed to serve a number of energy and wider Government policy objectives. Therefore, the principles which guide the Authority's review of the CUSC methodology must be based on delivering those policy objectives. Accordingly, the several objectives of the CUSC methodology related to the efficient operation of the energy system, the wider economy and society are described below, from which the principles that will guide the Authority's review of the CUSC methodology are then derived. These principles are set out in paragraph 3.9 below.

Objectives of transmission charging

Energy objectives

3.2 As discussed in the introduction to this consultation document, connection and transmission charging arrangements play an important role in the efficient operation of the electricity system. The way in which these charges are structured will impact on a range of high-level energy policy objectives. For example:

- Energy security: connection and transmission charges can impact on the types of power plants built, the way in which generation capacity is used as well as the pattern of final energy consumption.
- Sustainability: the design of the connection and transmission charging arrangements can affect the incentives for low-carbon and conventional generation technologies as well as the incentives to invest in demand-side response measures. This will impact on the total carbon dioxide (CO_2) emissions generated by the electricity sector.
- Affordability: the charges levied for connection and use of system influence the investment and operating costs for the electricity system and, ultimately, impact on the costs that are faced by consumers.

3.3 As such, the design of connection and transmission charging methodologies can be designed to encourage some or all of:

- Efficient use of the transmission network: transmission charges can provide incentives for the efficient dispatch of generation by ensuring that generators or the system operator face the full grid costs associated with their operating decisions. This can help to encourage the most cost-effective mix of generation capacity is utilized in meeting demand.
- Efficient investment in expanding the network: the connection and transmission

charging arrangements can provide incentives to encourage efficient and economic investments (e.g., through providing some form of 'locational' element in the charging methodology).

- Efficient investment in generation and demand: the connection and transmission charging arrangements influence both the investment in generation capacity (i.e., when and where power plants are built) and choices about where to locate sources of demand (i.e., electricity-intensive industries).
- Specific incentives to encourage low-carbon generating technologies: connection and transmission charging arrangements can be designed to support the uptake of low-carbon generation technologies. For example, through a set of differentiated charges that offer more favourable terms of low-carbon generation.

3.4 One of the key principles that guides connections and transmission charging methodologies is 'cost reflectivity'. As set out in the previous section, this means that the tariffs that are paid by the customer should represent the full costs of providing the transmission service. Cost-reflective charging provides the right signals to users of the transmission system, which should help to guide efficient consumption and investment behaviours.

3.5 In addition, connection and transmission charging methodologies frequently have regard to 'fairness' objectives, which encompass the ideas of distributional and inter-generational equality. Distributional equity considers the impacts of the methodology across different entities (e.g., are there groups of consumers who are bearing a disproportionate share of the costs of the transmission system?). Inter-generational equity considers how the costs and benefits of the transmission system are shared over time (e.g., are different generations paying a fair share of the costs of the transmission system?).

3.6 There are some tensions between objectives. For example, a system of transmission charging that is strictly focused on security of supply by incentivising network investment in order to meet peak demand may be less appropriate for incentivizing the take-up of renewable electricity. Renewable generation differs from conventional generation in a number of ways that can impact the requirements for transmission capacity. For example:

- Some types of renewable generation (notably wind) tends to be located far from areas of demand, which will require additional transmission capacity relative to conventional generation; and
- Many renewables are also intermittent (i.e., they only generate power when the wind blows or the sun shines) and therefore tend to be less predictable in terms of output compared to conventional generation. This means that a renewable

generator's contribution to transmission system demand at peak period may not be a fair reflection of its usage across the year. As such, a TUoS charge based on contribution to peak demand may under or over-charge renewable generation relative to the burden that it imposes on the transmission system.

These examples illustrate how the characteristics of renewable generation can impact the requirement for transmission capacity and also how a system of transmission charging based contribution to peak demand may not align with an objective to increase the level of renewable electricity.

Broader policy objectives

3.7 Beyond its impact on the energy system, the connection and transmission charging arrangements can also have an impact on broader economic and policy objectives. For example, to the extent that businesses value a secure, affordable and predictable electricity sector, the connection and transmission charging arrangements will impact on the perception of Oman as a place to do business.

3.8 Some aspects of the Government's broader policy agenda, as set out in the Ninth Five-Year Development Plan (2016-2020), that are relevant to transmission charging arrangements include[10]:

- Economic diversification: shifting from an oil-dependent economy to one in which growth is based on non-oil sectors is a strategic priority for Oman. The Ninth Five-Year Development Plan identifies a number of priority sectors (manufacturing, transport and logistics, tourism, fisheries and mining) which are considered to be the most promising sources of diversification. The Plan identifies the provision of an attractive business environment as one of the key challenges in attracting more local and foreign investment in these sectors. As was set out in the introduction of this consultation document, the costs associated with transmission charging may be a factor that internationally-mobile electricity-intensive manufacturing businesses consider when making their decisions about where to locate. As such, an efficient, simple and predictable transmission charging methodology can make a contribution to the Government's diversification objectives through increasing the attractiveness of the Omani economy as a place to do business.
- Furthering environmental sustainability: the plan sets out a range of objectives related to changes in the way in which energy is generated and consumed. This included an expansion in the use of renewable energy and a commitment to study the possibility of generating through other alternative energy sources (e.g.,

[10] The Ninth Five-Year Development Plan (2016-2020): A Plan Building on Achievements and laying Foundations for the Future, Supreme Council for Planning.

clean coal, biofuels). Renewable electricity generation differs from more conventional forms of generation (such as gas or oil-fired plants) both in terms of characteristics of generation (i.e., renewables tend to be more intermittent) and in terms of the location of the generation infrastructure (which may in some cases be located far from centres of demand on land that is less valuable or, conversely, can be more suited to distributed generation). As such, transmission charging arrangements that are geared to the requirements of conventional generation may be less appropriate for supporting an expansion of renewable electricity.

Principles of transmission charging

3.9 Based on the above discussion, we can identify a number of principles that can be used to guide the development of connection and transmission charging methodologies. These are:

- Efficiency: does the CUSC encourage efficient behaviours in terms of investment and operation of the transmission network and in terms of the type and location of generation and demand that is connected to the network?
- Non-discrimination: does the CUSC avoid undue discrimination (i.e., difference in the costs charged to different customers that cannot be objectively justified)?
- Cost reflectivity: does the CUSC target the costs of investment and operating the transmission network at those entities that are responsible for those costs?
- Fairness: are the costs to current and future consumers of using and connecting to the transmission network reasonable?
- Simplicity: is the CUSC simple to administer and understand?
- Transparency: are market participants able to predict future changes in connection and transmission charges? Is it clear to participants how they can reduce their costs?
- Future-proofed: is the CUSC appropriate given the changes that are expected within the electricity sector over the short to medium-term (i.e., creation of a spot market for electricity, wider use of cost-reflective ToU tariffs and greater penetration of renewable energy and DSM)?

3.10 In the following section, we will use these principles as the basis to assess the current CUSC.

Q1. Do you agree with the principles to guide the Authority's assessment of the CUSC methodology proposed in this section?

4. Key issues for reform of the CUSC methodology

4.1 In this section, in order to identify the aspects of the CUSC that could be reformed, we assess the existing CUSC methodology against the principles set out in the previous section and compare the CUSC with electricity transmission connection and use of system charges methodologies in place in other jurisdictions. The section also discusses the interactions between the CUSC methodology and OETC's price control review.

Connection charges

4.2 As was discussed in section 2, the current connection charging methodology charges generators and transmission-connected consumers the full cost of the connection infrastructure as well as a share of the total operating costs of maintaining the connection assets. Connection charges are based on a shallow charging methodology, which means that the connecting entity is not required to pay for any additional transmission infrastructure that is required in order to accommodate the new connection (e.g., reinforcements on the rest of the transmission network). These costs are recovered through licensed suppliers via the TUoS charges. The capital cost of the connection is annuitized so that OETC recovers the costs over the lifetime of the asset. Our assessment of the connection charging methodology against the principles set out in the previous section highlights a number of issues that the Authority intends to consider further.

Efficiency

4.3 The existing connection charging methodology has elements of cost-reflectivity, in that each generator and transmission-connected consumer is charged the full capital cost of the relevant connection assets. However, these capital costs do not include any costs of network expansion/reinforcement that may be required as a result of the connection. The use of a shallow charging methodology means that, in the presence of network congestion, generators and transmission-connected consumers do not face the full cost of their decision to connect. This contrasts with a 'deep' connection charging methodology in which entities are charged for the cost of their connection and the cost of any network expansion or reinforcement that is required to support that connection. Shallow charges may therefore result in sub-optimal decisions on where to locate new generation capacity and sources of demand, which will increase the cost burden on other consumers.

4.4 The latest OETC Capability Statement suggests that, for both the MIS and Dhofar transmission systems, there is a lack of capacity to accommodate demand at summer peak at certain locations (see Box 1 below for further details). This will limit the ability to make new transmission connections in these areas unless action is taken to reinforce the transmission network (and/or transfer demand from heavily loaded to more lightly loaded grid stations). Furthermore, OETC expect that the instances of system stress could increase in future as demand continues to grow. As such, this issue may intensify over time.

4.5 The Authority notes that the existence of some transmission system constraints is not unexpected given the rapid growth in peak demand in Oman over the recent past. Between 2010 and 2016, peak demand grew by an average of 7.30% and 5.48% per year in MIS and Dhofar, respectively.[11] However, in making its assessment of possible future reforms to the CUSC, the Authority is keen to understand whether there are particular parts of the transmission networks where transmission constraints are especially severe.

4.6 This helps to illustrate a potential drawback of a shallow charging methodology in the presence of network congestion. Under the existing charging arrangements a generator or transmission-connected consumer will face no penalty from locating in an area of the transmission system that is already under stress, even where this decision requires that OETC make additional investment to upgrade the system to accommodate the connection.

4.7 The potential issue of a lack of locational signals in the connection charging methodology could be compounded were there to be a substantial increase in the level of renewables electricity generation in Oman, especially where renewable generation is located far from the major centres of demand (as is the case for the 50MW wind farm project that is currently under development in Thumrait area). Renewable generation that is located far from the major sources of demand will tend to require additional transmission capacity, which increases the costs of the system on consumers.

4.8 It is important to note, however, that in the absence of material transmission constraints, there would be no difference between the connection charge based on a shallow and deep charging methodologies. Put simply, the lack of network congestion would mean that there would be no network expansion or reinforcement required as a result of the connection, which means that the connecting entity would simply face the cost of the connection. In this case there would be no benefit to the introduction of deep connection charges.

4.9 In addition, there are some other practical considerations that would influence the choice between shallow versus deep connection charges. These are:

[11] Authority's Annual Reports

- Do connecting entities have a choice about where to locate? In the presence of transmission constraints, deep connection charges give a signal to connecting entities to locate in uncongested areas of the network. Realizing the benefits of this price signal requires that entities have some choice in where to locate. The Authority notes that while transmission-connected customers may have some flexibility in where they locate their business within Oman, the number of sites where generation developments are permitted are quite limited; and
- Would a system of deep connection charges impact on the attractiveness of Oman as a place to locate an electricity-intensive business? For electricity-intensive businesses that are internationally mobile, the costs of connecting to the transmission network could influence its decision about whether to locate in Oman or elsewhere. To the extent that a system of deep connection charges reduces the attractiveness of Oman (relative to other jurisdictions with lower connection charges) then there could be substantial economic costs associated with making connection charges fully cost reflective. However, the Authority notes that transmission costs are only one of a number of factors that a company will consider (e.g., access to skilled labour force, access to markets, Government policy and legal framework being some notable other factors) in making its decision about where to locate.

This discussion highlights some of the technical and operational preconditions that would need to hold in order to realize the potential benefits of moving from a shallow to a deep connection charging methodology.

4.10 Beyond the issue of incentivizing transmission connections in locations that help to minimize the costs of network reinforcement, the connection charging methodology should also provide incentives to ensure that connections happen in a timely and cost-efficient manner. These issues are discussed further below in the context of the interactions between the CUSC and OETC's price control review.

Box 1: Examples of network congestion from OETC's 2017 Capability Statement

OETC is required through its license to develop an annual Capability Statement that includes an assessment of system performance. OETC conducts power system studies based on the extreme cases of maximum and minimum system demand to understand the performance of the transmission system when it is most stressed. The results of these studies are used to identify the parts of the system where there is sufficient (or spare) capacity and those parts of the system that are under stress and will need to be reinforced.

The 2017 Capability Statement set out the results of the power system studies for MIS and Dhofar systems. The results for MIS showed:

- The majority of the 220/132kV grid stations had an adequate amount of spare capacity to support new connections over the period 2017-21. However, some grid stations show a lack of capacity to support new connections at summer peak;
- At summer peak, thirteen 132-32kV grid stations will operate above their firm capacity in 2017. This number is expected to fall over the forecast period due to load shifting and network reinforcement; and
- A small number of 132kV overhead lines are expected to be operating above their firm capacity over the summer peak in 2018 and 2020.

The results for Dhofar showed that:

- Awqad 132/33kV grid station showed a lack of capacity in 2017 and Thumrait grid station showed a lack of capacity in 2020.

OETC sets out in the capability statement the actions that it will take to address the issues identified through the power system studies. First, OETC's reinforcement plan will make strategic additions to the network by adding new circuits and/or increasing the capacity of grid stations. Second, through agreement with the distribution companies, load can be transferred from more heavily loaded grid stations to more lightly loaded grid stations.

It is worth noting, however, that OETC expects that the level of stress on the transmission system will increase in future as demand increases. Indeed OETC states that:

"It is possible that further non-compliance [with the Transmission Security Standard} may arise in future until the system becomes substantially more robust through interconnection."

Source: Five-Year Annual Transmission Capability Statement (2017-2021), OETC

Non-discrimination

4.11 The CUSC offers generators and transmission-connected consumers non-discriminatory terms for connection to the network in that they are charged directly for the cost of their connection asset. However, the methodology for allocating connection operating costs (through which each entity faces a share of the total operating costs based on the value of their connection asset) potentially discriminates across connections. This can be illustrated through an example (reproduced from the CUSC based on the 2016-18 MIS price control and the 2016 connection assets GAV of MIS[12]):

[12] Connection and Use of System Charge Methodology Statement (p.12)

2016 MIS connection charge opex in 2016 prices: RO 3,146,000

2016 OETC connection asset GAV (minus user maintained assets): RO 152,232,705

TRC factor = (3,146,000 / 152,232,705) x 100 = 2.09%

For a company with connection assets of 64,913,705, the transmission running cost charge would be:

TRC = RO 64,913,705 x 2.09% = RO 1,257,459

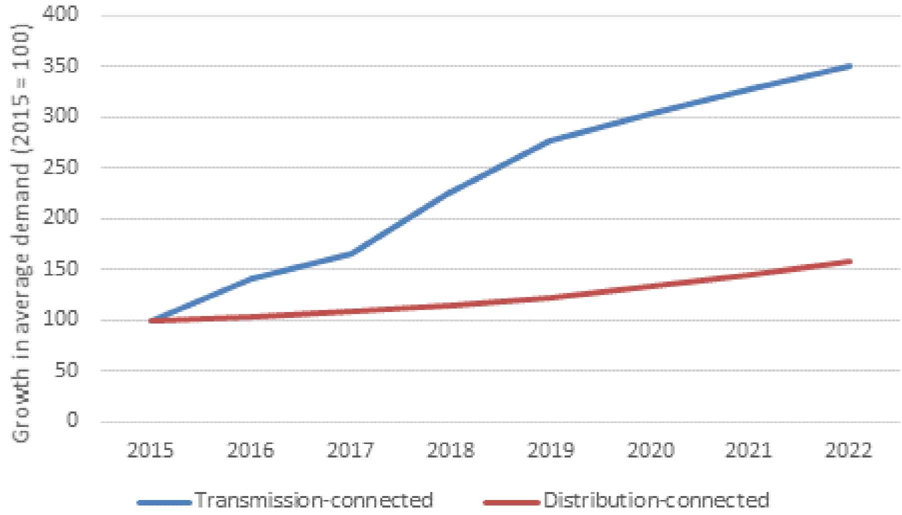
regardless of what the actual costs of running and maintaining the asset are. Moreover, the approach to calculating an individual customer's TRC does not take account of the age and condition of the assets in question. However, the Authority also notes that the methodology is relatively simple to implement (and to understand for Licensees) and ensures consistency with the price control settlement (i.e., it ensures that the full MAR for connection operating costs is allocated across non-user maintained connections).

Fairness

4.12 Turning to the fairness criteria, as set out in Section 2, connecting entities have the choice of paying the costs of their connection up-front or over time (or through a combination). Where entities decide to pay the costs over time, the annual charge is calculated based on the weighted average lifetime of the connection asset and the WACC. Annuitizing the capital costs of connections across the lifetime of the asset can help to achieve a fair intergenerational distribution of costs. Put simply, this means that all consumers – both current and future - that benefit from the connection asset are required to pay a share of the costs.

4.13 However, while spreading costs over the life of the asset contributes towards a fair allocation of costs and benefits over time, the requirement for OETC to meet the up-front costs of providing a connection, whilst recovering these costs over the lifetime of the asset, does potentially impact on OETC's cash-flows and financeability. This is an issue that could intensify given the increasing numbers of large consumers requesting connection to the transmission network. This trend is illustrated in Figure 2, which shows the projected growth in transmission and distribution-connected demand from 2015 to 2022. These projections suggest that transmission-connected average demand will see 20% year-on-year growth, compared to 7% for distribution-connected loads. Furthermore, this projection (which was developed in 2016) may not take account of the latest market trends (notably the introduction of cost-reflective tariffs in 2017).

Figure 2: projected growth in average demand (2015=100)

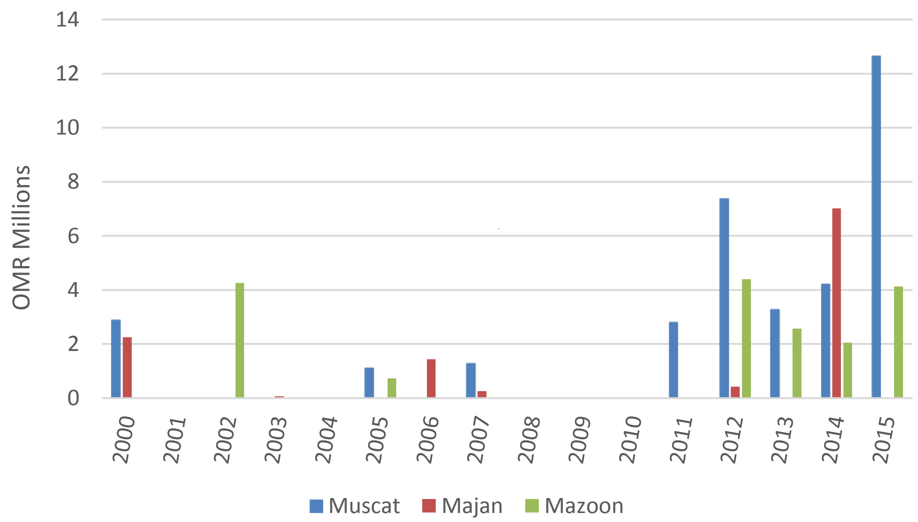


Source: OPWP Seven-Year Statement 2016-2022

4.14 The impact on OETC's cash-flow could be alleviated by requiring some or all of the costs of a new connection to be recouped up-front (rather than over the lifetime of the asset). Moving to this alternative basis for the recovery of connection costs would require an assessment of the likely impact on end-user prices (and associated subsidy requirements).

4.15 The profile of connection capex (i.e., the original value of the connection asset and the year in which it was installed) for Muscat, Majan and Mazoon Discos is shown in Figure 3. This shows that the incidence of connection capex is quite 'lumpy' over time. Connection charges are a pass-through for the distribution companies, which means that a shift towards paying for the cost of connections up-front would result in a large increase in pass-through in certain years (and, therefore, in the subsidy requirements for that year). The Authority is therefore keen to understand the possible subsidy implications associated with making this change in the way that connection capex is recovered.

Figure 3: profile of connection capex for Muscat, Majan and Mazoon (values based on nominal value of asset at the time of installation)



Source: OETC

Other principles

4.16 When considering the potential changes to the CUSC described above, the Authority will also be mindful of the other principles of connection and use of system charges outlined earlier. For example:

- Simplicity: the use of shallow connection charges that just recover the cost of the connection (but not the wider costs associated with any system expansion or reinforcement) from the connecting entity is relatively straightforward, which means that it is simple to administer and understand of market participants. Some of the potential changes to the CUSC discussed above would result in additional complexity, so the benefits of those changes will need to be balanced against any loss of simplicity.
- Transparency: both the connection charging methodology and the annual statement of transmission system charges (which sets out the application fees for connections) is published by OETC. During their application, connecting entities are provided by OETC with an indicative estimate of the capital costs of a connection. Once the actual costs are known, this will become the basis for connection charging. This approach transfers the risk of unanticipated increases in connection costs to the connecting entity, but arguably OETC is better placed to manage and mitigate those risks and consequently should bear (at least a portion of) those risks. This approach is also not as transparent as it could be,

since the connecting entity does not know the cost of connecting before it agrees to the connection offer. The Authority will seek to ensure that any changes it makes to the CUSC help to enhance transparency of connection charges.

- Future-proofed: as discussed in Section 3, an increase in the volume of grid-connected renewable electricity can impact on the required transmission network capacity. For example, grid reinforcements may be required to accommodate the intermittent nature of renewable electricity and, for certain technologies, because of the tendency for renewable generation to be located far from where the electricity is consumed (although this is likely more of an issue for wind rather than solar generation). Given the use of a shallow charging methodology, an increase in the penetration of renewable generation could intensify the issues around generators making sub-optimal location decisions.

Q2. Do you agree with the Authority's assessment of the existing connection charging methodology?

Q3. In your view, has the use of a shallow charging methodology resulted in sub-optimal location decisions by generators and transmission-connected consumers?

Q4. In your view, has the current methodology for calculating the TRC resulted in an unfair allocation of costs across connections?

Q5. In your view, has the current approach of annuitizing connection costs led to cash flow/financeability issues for OETC?

Transmission use of system charges

4.17 The TUoS charges recover the cost of installing, operating and maintaining the transmission network as well as the costs of scheduling and dispatch of electricity generation. The MAR for these activities is set by the Authority at periodic price control reviews. The TUoS charges are paid by licensed suppliers and transmission-connected consumers (who are required to have a Supply Agreement with a licensed supplier). Costs are allocated to licensed suppliers according to their contribution to Maximum Transmission System Demand (MTSD), which is defined as the maximum average electricity demand in an hour, expressed in megawatts (MW).[13]

[13] Identical charges are applied in the MIS and Dhofar regions. The TUoS calculation is therefore based on the aggregate MAR and MTSD for both regions.

4.18 OETC publishes a Statement of Transmission System Charges in December of each year. This sets out the TUoS charges for the forthcoming year (specified in Omani Rials per MW). These charges are based on the MAR and an estimate of maximum transmission system demand (which is expected to occur during the summer months). Invoices are sent to each licensed supplier based on their estimated shares of maximum system demand. At the end of the year, once the actual maximum transmission system demand and the shares attributable to each licensed supplier are known, OETC sends revised invoices to correct for any differences between estimated and actual values.

4.19 Assessing the transmission charging methodology against the principles set out in the previous section highlights a number of issues that the Authority intends to consider further.

Efficiency

4.20 While the CUSC methodology allows OETC to recoup the full MAR, the current system of transmission charges are not fully cost-reflective. Indeed, there are several aspects of the charging methodology that may be reducing the efficiency of investment and operation decisions. These are: (1) charges are levied on demand only; (2) TUoS charges do not vary by location; (3) identical charges are applied across MIS and Dhofar; and (4) the treatment of costs associated with balancing and dispatch (the costs of which are recouped through the TUoS charges but could in principle be recouped through a separate charge).

4.21 Currently, TUoS charges are paid by licensed suppliers with none of the cost burden falling on generators. This means that generators do not face any economic signals with respect to its use of the system. This may mean that the efficiency of investment and operating decisions is reduced (e.g., generators may choose to locate or to operate at certain times of the day or year that increase transmission use of system costs compared to locating elsewhere or operating at different times of day or year).

4.22 In addition, the TUoS charges under the existing methodology do not vary according to location. This means that transmission-connected customers may not face the correct economic signals from connecting at different points on the network, which can lead to inefficient decisions from companies about where to locate their operation (e.g., it may result in an inefficiently high level of investment in areas where there are high transmission costs). It is worth noting, however, that transmission-connected customers do face electricity charges that vary according to time of year (rate varies by period: January-March, April, May-July, August-September, October and November-December) and time of day (peak versus off peak), which provide some price signals to reduce consumption at times that increase the transmission use of system costs.

4.23 There are a number of technical and practical constraints to realizing the economic benefits associated with more cost-reflective charges for use of the transmission network. As discussed in paragraph 4.8 above, introducing a locational element into TUoS charges can yield cost savings where there are material constraints on the transmission system (which are required in order to create the price signal) and some flexibility for users of the transmission system to be able to respond to that signal (e.g., in terms of where they locate). Where this is not the case, there would be limited benefit of introducing a locational element to TUoS charges on generation or demand.

4.24 An additional factor that will impact on the realization of the benefits of more cost-reflective TUoS charges is the way transmission network users would treat the TUoS charges. For example, under the current system of power purchase agreements (PPAs), generators would treat TUoS charges as a pass-through cost (i.e., the full cost of the transmission charges would be reflected in the price that the generators charge to OPWP for power supplied). This means that, under the current system of procuring power through PPAs, generators would be unlikely to respond to a price signal through TUoS charges.

4.25 This may change over time with the introduction of the spot market. The creation of a spot market for electricity has the potential to lower production costs by ensuring the optimal use of available capacity. That is, generators will 'offer' into the market based on their cost of production and this allows for the most cost-effective generation to be dispatched in order to meet demand. The creation of the spot market therefore intensifies the need for generators to face the correct economic signals for the use of the transmission network (i.e., TUoS charges that reflect the burden that generators are creating on the network) to help ensure that the market can reach the most efficient outcome in terms of the use of available capacity.

4.26 Another factor that may be affecting the efficiency of investment and operating decisions for users of the transmission system is the fact that identical charges are applied across the MIS and Dhofar systems. As set out above, the TUoS charges are calculated based on the aggregate MAR and MTSD for the MIS and Dhofar regions. However, the two regions have different characteristics in terms of maximum transmission system demands and the costs of the transmission system. Based on the MAR and the MTSD projections (see Table 2).

4.27 Dhofar accounts for around 8% of aggregate MTSD but only around 4% of aggregate MAR. This means that a TUoS charge based on the aggregate MAR and MTSD for the two regions will over-charge transmission system users in Dhofar (i.e., the TUoS charge will be higher than the cost of providing the service) and under-charge users in MIS.

Table 2: MTSD and MAR for Dhofar and MIS in 2017

System	MTSD (MW)	MAR (OMR million ,2016 prices)
MIS	6,968	67.2
Dhofar	598	2.9
Total	7,566	70.1

Source: OETC Final Price Control Proposal (2016-18)

4.28 Finally, the TUoS charges currently include OETC's costs associated with balance and dispatch of electricity. In principle, a more cost-reflective approach could be to separately identify the costs associated with transmission from the costs associated with balancing and dispatch and have separate charges for each that reflect the full cost of providing the service. The Authority intends to explore the cost of providing balancing and dispatch services, how these costs should be allocated across users of balance and dispatch services and the extent to which this distribution of costs aligns with the way that these costs are currently recovered through the TUoS charges.

Fairness

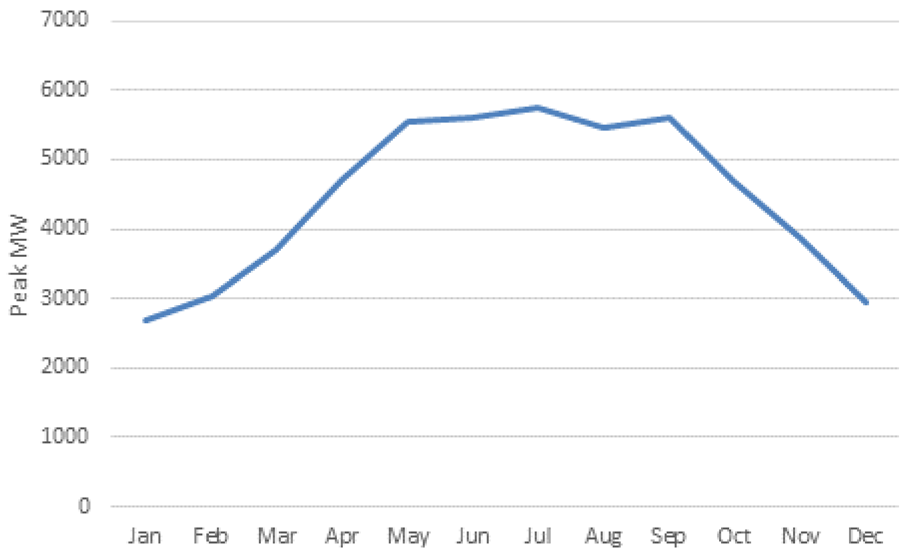
4.29 The lack of cost-reflectivity in the TUoS charges highlights a range of issues relating to the fairness of charges to different users of the transmission system. For example, it could be argued that the way in which costs are allocated across geographies (i.e., Dhofar versus MIS), users (i.e., generators versus suppliers) and network locations (i.e., congested versus uncongested parts of the network) is not fair as it does not accurately represent the costs of providing transmission services to those users. However, the allocation of costs does appear to be relatively fair from an inter-generational perspective (i.e., in broad terms, all consumers who benefit from the assets are required to contribute).

Transparency

4.30 The way in which TUoS charges are allocated to suppliers helps to create an incentive for reducing consumption at peak periods for certain customers. As was described in Section 2, TUoS charges are levied on large customers based on their share of maximum transmission system demand (i.e., the one hour of maximum transmission system demand in a year). The inclusion of this element in the electricity transmission tariff faced by large consumers should help to manage peak demand by ensuring that these consumers face a cost that to some extent reflects the burden that they are placing on the transmission system. In principle, this approach to charging potentially creates a powerful incentive for customers to manage their demand during peak periods. This should help to shift some demand away from peak period and reduce the requirement of some investment in transmission and generation capacity.

4.31 However, it is worth considering whether a more powerful incentive to reduce peak demand could be created through moving from a charge based on a single snapshot of peak demand to one based on multiple snapshots. Moving to a system of charges based on multiple snapshots of system demand (e.g., transmission costs based on the average share of the two hours of highest transmission system demand in a year) can help to intensify the incentive on consumers to manage their demand. That is, consumers will need to manage their peak demand over a longer period to increase their chance of minimising their consumption during both hours. This approach may be particularly appropriate for the MIS where peak demand is relatively high throughout the summer months (see Figure 4).

Figure 4: MIS system peak demand (2015)



Source: Annual Report 2016, AER

4.32 The Authority notes, however, that some care would need to be taken in the design of a system based on multiple snapshots. It is possible that the peak hours could be concentrated during a short period of time, which may undermine the incentive for transmission-connected customers to manage their peak demand over a sustained period of time. For example, the three hours of maximum transmission system demand for the MIS were on consecutive days in both 2016 and 2017 (see Table 3)

Table 3: maximum transmission system demand (MIS)

2016		2017	
Date	MTSD (MW)	Date	MTSD (MW)
10-06-16	6,052	29-05-17	6,230
11-06-16	6,104	30-05-17	6,289
12-06-16	6,105	31-05-17	6,304

Source: OETC price control returns, Authority analysis

4.33 It is also important to note that the allocation of TUoS charges entirely on the basis of peak transmission system demand means that large consumers do not face a strong incentive to reduce their overall demand (i.e., Regulated Units Transmitted (RUT)). This incentive is, however, provided through the bulk supply tariff element of the CRT, which as noted above also includes incentives (through charges that vary according to season and by time of day) to manage consumption during peak periods.

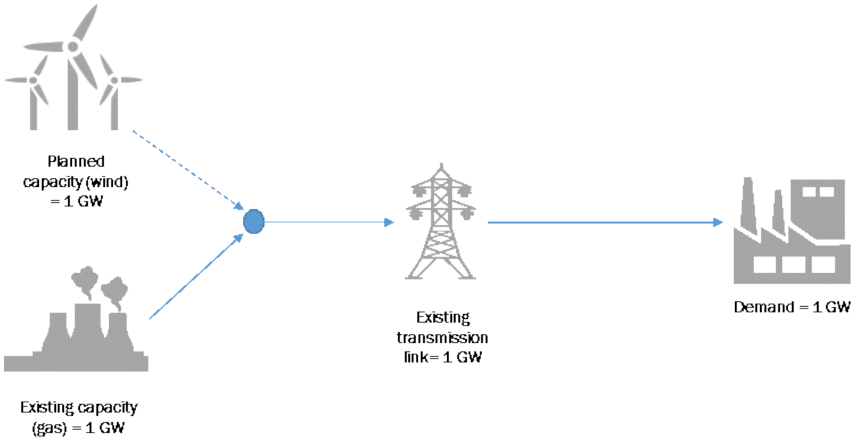
4.34 Furthermore, as set out in Section 1, only large customers (consuming over 150 MWh of electricity per year) face a cost reflective tariff for electricity. The majority of electricity consumers face a Permitted Tariff, which charges a per unit (KWh) that level of consumption. While these consumers pay a share of the costs of the transmission system, this cost is not a separate component of their tariff. This means that these consumers do not face a clear price signal about the cost that their consumption is placing on the transmission system.

Future proofing

4.35 A substantial increase in the level of renewable electricity would affect the electricity system in a number of ways. Renewable electricity tends to be intermittent and, as a result, often has a lower capacity factor compared to conventional sources. What this means is that renewable generation will not entirely replace conventional generation, which will remain connected to the network to complement the intermittent renewables. This potentially alters the relationship between the level of generation capacity and the required level of transmission capacity. Put simply, the level of transmission capacity no longer needs to match the level of generation capacity.

4.36 This is illustrated with the simple example shown in Figure 5. Suppose that the entire power system is made up of an existing 1 GW gas plant and 1 GW of transmission capacity that is serving 1 GW of peak demand. Suppose also that a 1 GW wind plant is considering connecting to the same network node as the gas plant. In this situation, no new transmission capacity is required. When the wind is blowing, the gas station should reduce its output as wind is the lower-cost option to serve the demand. The key driver of transmission capacity remains the level of peak demand.

Figure 5: illustration of the relationship between capacity and demand



Source: Newberry (2011), High-level principles of GB transmission charging

4.37 While the new wind plant in this example does not affect the level of transmission capacity that is required, it may require changes to the way in which the costs of the transmission system are allocated (in a scenario where part of the TUoS charges are levied on generation). As set out above, intermittent renewables tend to have lower capacity factors than conventional generation sources. Allocating the costs of transmission based on the share of peak system usage may not be representative of the costs that renewable generation places on the transmission system throughout the year.

Q6. Do you agree with the Authority's assessment of the strengths and weaknesses of the existing CUSC methodology?

Q7. In your view, has the existing transmission charging methodology resulted in, or could it result in, sub-optimal location and operation decisions by generators and transmission-connected consumers? As such, do you see that there would be benefits to generators paying a share of TUoS charges and/or introducing a locational element to the charges?

Q8. In your view, would changing the basis for TUoS charges from single to multiple snapshots of maximum system demand result in more powerful incentives to reduce demand at peak periods? Should a share of TUoS charges reflect the RUT for each supplier?

Q9. In your view, would there be a benefit to introducing a separate charge for dispatch and balancing?

Comparison to international best practice

4.38 An examination of the way in which connection and transmission use of system charges are structured in other jurisdictions can help to identify ways in which the CUSC could be refined. In this section, we summarise the key aspects of the charging methodologies used a selection of other countries.

4.39 A summary of the key aspects of connection and transmission charging arrangements in a range of markets is shown in Table 4. In the following sub-sections, we explore how the transmission charging arrangements in different countries have been designed to overcome some of the issues highlighted above.

Table 4: key characteristics of selected international transmission and connection charging methodologies

Location	Transmission charging	Connection charging
Abu Dhabi	▪ Charges on demand only ▪ Distribution companies charged based on annual units consumed (i.e., MWh) ▪ TUoS tariff varies by season and time of day	▪ Shallow charging methodology

Australia (NEM)[14]	▪ Charges on demand only
	▪ TUoS tariff composed of
	  o locational element (nodal pricing) based on contribution to maximum system demand
	  o non-locational element (based on either capacity or demand) that is the same in all locations
		▪ Shallow charging methodology

Estonia	▪ Charges on demand only ▪ TUoS tariff does not include locational component	▪ Deep charging methodology

[14] The National Electricity Market (NEM), includes the States and territories of Queensland, New South Wales, Victoria, South Australia and Tasmania.

Great Britain	▪ Charges on generation (17%) and demand (83%) ▪ TUoS tariff composed of locational element (zonal pricing) and non-locational elements ▪ Generation charges – which are based on capacity (MW) - vary by technology type to reflect the different impacts that intermittent and non-intermittent capacity places on the transmissions system (e.g., certain charges adjusted to reflect generation load factor) ▪ Demand tariff is based on capacity (MW) and demand (MWh) charges. Capacity charges are based on the consumer's averaged demand in the three half-hours of the year where demand is the highest.	▪ Shallow charging methodology
Northern Ireland	▪ Charges on generation (25%) and demand (75%) ▪ TUoS tariff on generation is based on capacity (MW) and is calculated individually for each generator (nodal pricing) with a capacity above 5MW ▪ TUoS charges on consumers are based on demand (MWh) and vary according to season and time of day (but not location)	▪ Shallow charging methodology
Republic of Ireland	▪ Charges on generation (25%) and demand (75%) ▪ TUoS tariff on generation is based on capacity (MW) and is calculated individually for each generator (nodal pricing) with a capacity above 5MW ▪ TUoS charges on customers are based on capacity (MW) and demand (MWh)	▪ Shallow charging methodology
Sweden	• Charges on generation (36%) and demand (64%) • TUoS tariff on generator and customers has a locational element, with tariff geographically differentiated between north and south regions. • TUoS tariff based on capacity (MW).	▪ Deep charging methodology

USA (PJM)[15]	• Charges on demand only
	• TUoS tariff composed of
	  ○ locational element (nodal pricing) based on suppliers daily peak demand
	  ○ non-locational element based on demand
	• Auctioned FTRs provide a potential hedge against the costs of network congestion
		▪ Deep charging methodology

Sources: AEMO, Eirgrid, ENTSO-E, Northern Ireland Electricity Networks, Ofgem, PJM, SONI

Locational pricing

4.40 With the exception of Abu Dhabi and Estonia, all of the transmission charging methodologies incorporate some form of locational element in the TUoS charges (although Estonia does incorporate a locational element through deep connection charges) that reflects the impact of generation/demand at different points on the transmission network. There are two broad approaches to locational pricing:

- Nodal pricing: under this approach (which is adopted in Ireland, the NEM and PJM), the transmission tariff is based on individual prices reflecting the marginal costs at each location (or 'node') of the transmission network. In theory, nodal pricing offers the most efficient approach as the price signals most accurately reflect the burden of incremental demand at each point on the network at a specific time.
- Zonal pricing: under this approach (used in Great Britain) the transmission system is divided into separate charging zones and a separate tariff is charged in each zone. This is a simpler approach than full nodal pricing but can blunt the price signals that are faced by generators and consumers.

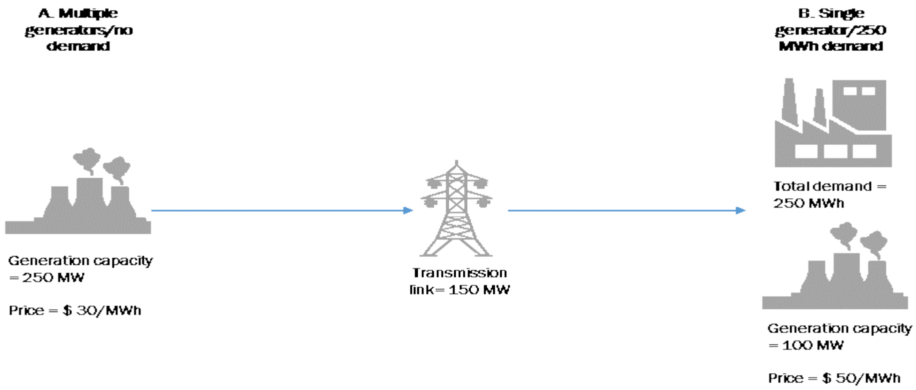
4.41 While locational prices can provide sharper price signals to transmission users about the costs they are imposing on the system, the calculation of these prices relies on complex system modelling, which can make the charges more difficult to understand and predict for participants. The PJM market in the USA uses a financial instrument called Financial Transmission Rights (FTRs) to help participants to manage the uncertainty related to congestion costs. The FTRs, (which can be acquired from the PJM through auctions or purchased on the secondary market), allow the holders to hedge against losses that result from congestion. A simple illustration of how an FTR works is shown in Box 2.

Box 2: financial transmission rights in the PJM market

The use of locational pricing based on daily peak demand exposes participants in the PJM market to price uncertainty due to congestion costs. In the context of this market, congestion costs can be defined as the costs that are paid by demand that would not be paid if the transmission system were free of congestion.

During constrained conditions, the PJM market collects more from demand than it pays to generators. The surplus 'congestion rent' is allocated to entities that hold FTRs. The FTR therefore provides market participants a hedge against the price uncertainty due to congestion.

The working of FTRs can be illustrated with a simple example. Suppose that the electricity system is made up of two nodes: (1) node A: where there are multiple generators with a combined capacity of 250MW, which can produce electricity at a price of $30/MWh; and (2) node B: where there is a single 100MW generator, that can produce electricity at a price of $50/MWh, and demand of 250MWh. The two nodes are connected by a 150MW transmission link.



In this example, there is sufficient generation capacity at node A to meet the entire demand at node B, but this is not possible as there is insufficient transmission capacity. As such, generators at node A provide 150 MWh and the remaining 100 MWh is provided by the more expensive generation capacity at node B.

The price paid by demand is set by the marginal generator at B, which means that the total payment by demand is given by:

Payment by demand = $12,500 ($50/MWh x 250 MWh)

However, as set out above, given the existence of congestion, the PJM collects more from demand than it pays to generators. In this case, the payments to generators are:

Payment to generators at A = $4,500 ($30/MWh x 150 MWh)

Payment to generators at B = $5,000 ($50/MWh x 100 MWh)

Which results in a congestion rent (i.e., the additional cost paid by demand that would not be paid if there was sufficient transmission capacity so that the generators at A could meet the entire demand) of:

Congestion rent = \$3,000 (\$12,500 - \$4,500 - \$5,000)

Which is be allocated to the holders of FTRs. Notice that, in this case, the FTR allows the supplier to offset the additional costs of having to meet a part of demand from the more expensive generation capacity at node A.

Source: PJM learning center

Incentivizing efficient consumption behaviors

4.42 The basis for allocating transmission charges also varies across different markets. Many of the transmission charging methodologies include a capacity component within charges as well as a demand component (i.e., a portion of TUoS charges are allocated based on contribution to maximum transmission system demand with the remainder allocated based on total units demanded). This approach places an incentive on consumers to manage both total and peak consumption.

4.43 The system in place in Great Britain, where the transmission charges on load is based on average demand across the three half-hours of the year where demand is the highest (known as the triad periods) provides a strong incentive to reduce demand at peak periods. As described above, the use of multiple snapshots (coupled with the requirements that each triad cannot be within 10 days of one another, in order to avoid all three coming within a single period of peak demand) helps to ensure that consumers consistently manage their load throughout peak periods.

Accommodating intermittent renewables

4.44 The transmission charging methodology in Great Britain is also an interesting case study in terms of the way it treats intermittent and non-intermittent generation. Great Britain has an ambitious target to increase the level of renewable electricity to 30% by 2020. The electricity regulator (Ofgem) argued that a transmission charging methodology that charged generation based entirely on capacity didn't appropriately capture the cost that intermittent generators impose on the transmission system (and could therefore act as a constraint on meeting the renewable electricity target).[15] As such, the transmission charging arrangements were changed to attempt to capture the impact of intermittent renewable generation on the transmission network (i.e., renewables are exempt from the peak time component of transmission charges and other components of the transmission charges are adjusted by the generation load factor). These adjustments act to reduce the transmission charges faced by renewable

[15] Ofgem (2014) 'Project TransmiT: Decisions on proposals to change the electricity transmission charging methodology'

generation.

Connection charges

4.45 In the majority of the international examples outlined above, connections are charged for based on a shallow charging methodology. The exceptions are the PJM, Estonia and Swedish markets which require connecting entities to pay for both the cost of the connection asset and the additional costs of any network reinforcement, which is assessed through power system impact studies.

4.46 Deep connection charges provide very efficient locational signals to connecting parties, which can help to lower the overall cost of the transmission system. However, there are some potential drawbacks of deep charges (which may explain why the majority of countries surveyed opt for shallow charges) including the fact that major network reinforcements may block generator developments and/or reduce the attractiveness of Oman as a destination for internationally mobile electricity-intensive businesses.

System balancing

4.47

4.48 Table **5** sets out the approach to recovering system balancing charges in a range of countries. In each of the examples shown, the balancing use of system charges (BUoS) are levied on both generators and suppliers and is levied based on the basis of energy (MWh). This reflects the extent to which different users of the transmission system are causing system balancing activities to take place (e.g., a supplier demands more energy than was anticipated, causing additional generation to be dispatched).

Table 5: key characteristics of selected system balancing charging methodologies

Location	Key characteristics of balancing charges
Great Britain	• Imbalance charges are paid by generators and suppliers. Interconnectors have been exempted from paying balancing charges since 2012. • Charges are calculated on a half hourly basis (GBP/MWh) and billed on daily settlement
Germany	• Imbalance charges are paid by generators and suppliers. • Charges are calculated on a quarter hourly (EUR/MWh) basis and billed on a monthly settlement
Netherlands	• Imbalance charges are paid by generators and suppliers. • Charges are calculated on a the basis of MWh and billed on a weekly settlement

Source: National Grid, ENTSO-E

Interactions between the CUSC and the price control review

4.49 As discussed above, the CUSC sets the methodology through which OETC's MAR is recovered through connection and use of system charges. As such, it is important to consider the interdependencies between the CUSC and the current price control review in order to ensure that the connection and transmission charging methodology is not creating incentives for OETC, generators and/or transmission-connected consumers that leads to inefficiencies in the setting of the MAR (i.e., to MAR being set higher than it needs to be).

4.50 One area of interdependency is through the impact of the CUSC on OETC's working capital and financeability. As set out in Section 2, connecting entities have the choice of paying the capital cost of their connection up-front or through annual payments across the lifetime of the asset (or through a combination). The choice of connecting entities has an impact on OETC's cashflow (e.g., when an entity wants to pay for the connection over time, then OETC has to pay the full cost up-front but will recoup this cost in instalments over time).

As such, the greater the proportion of entities that wish to pay their connection costs in instalments over time, the higher will be OETC's working capital requirement that needs to be funded through the MAR. In reviewing the CUSC methodology alongside developing the price control for OETC, the Authority will needs to consider the cost impact of funding additional working capital for OETC versus the potential impact on subsidy and economic competitiveness of requiring a greater proportion of connection costs to be paid up-front.

Q10. In your view, how would up-front charging for connections impact parties who were considering connecting to the transmission network?

4.51 Another area is the potential impact of speculative requests (e.g., an entity requests a connection but, for whatever reason, decides not to connect or connects later than expected) and/or inappropriately sized connection (e.g., an entity requests a connection based on an expectation of generation capacity or load which turns out to be too high). In both of these cases, the connecting entity is required to bear the cost of the connection asset but not for any network reinforcement that is required as a result of the connection.

4.52 What this means is that, while the connecting entity faces the full cost of the connection asset (irrespective of the size of the connection and whether that connection is used), the costs of the wider network reinforcement will be recovered from other customers through the TUoS charges. This means that OETC need to undertake effective due diligence on all applications in order to make sure that it is only responding to necessary and appropriately sized connection requests.

4.53 A related issue is the extent to which connecting entity default on its connection agreement. For example, when a transmission-connected consumer goes out of business and cannot pay any of the remaining capital costs for their connection (assuming it was paying over-time rather than up-front). In this case, OETC will need to recover the residual capital costs through another route.

Q11. In your view, have there been instances of entities making speculative and/or inappropriately sized requests?

Q12. If yes, do you believe that the current charging methodology has contributed to this issue?

4.54 Another potential interaction between the CUSC and the price control review is in terms of the efficiency with which OETC procures and delivers connections. OETC is required to provide applicants with an indicative offer to connect, which sets out the initial connection charge based on the expected capital cost of the connection. The connection charges will then be adjusted once the connection asset is built (and the costs are known).

4.55 The technical specification of the connection is based on the Minimum Scheme. The Minimum Scheme is defined as the design with the lowest cost to provide the requested connection capacity. In developing, procuring and delivering connections based on Minimum Scheme, OETC is bound by its license conditions, which obligate OETC to 'develop, operate and maintain an efficient and economic transmission system in accordance with the Transmission Security Standard and the Grid Code'. There is, however, no economic incentive to encourage OETC to deliver connections as efficiently and quickly as possible (as the full cost and risk is borne by the connecting entity), which could result in inefficiently incurred capex.

Q13, In your view, would there be advantages to introducing within the transmission price control a specific incentive to encourage efficient and timely connections?

5. Options for reform

5.1 The previous section assessed the existing CUSC methodology against a set of guiding principles (set out in Section 3). This identified a number of areas of the CUSC that could potentially be reformed to better align the methodology with OETC's principal objective to operate the transmission system in an efficient and economic manner. The section also explored the approach to transmission charging in other countries, which demonstrated how regulators in other jurisdictions tackled some of the potential issues identified with the CUSC.

5.2 In this section, we set out the high-level options for reforming the CUSC that could potentially address the issues identified. These reform options can be categorized as:

(1) reforms to incentivise more efficient decisions related to location and operation from generators and transmission-connected customers;

(2) reforms to incentivise more efficient consumption behaviors;

(3) reforms to accommodate an increase in renewable generation; and

(4) reforms to the connection charging methodology.

As discussed in the previous section, there are a number of practical and technical issues that would affect whether the benefits associated with these reforms could be realized in practice (e.g., existence of material network constraints, ability of transmission users to respond to price signals, whether transmission costs would be treated as a pass-through or not, etc.). The Authority intends to consider each of these issues in its assessment of potential reforms to the CUSC methodology.

Incentivizing more efficient locations and operations

5.3 In light of the introduction of the spot market for electricity and the expected increased stress on the transmission system as peak demand continues to grow, it is prudent to consider whether the TUoS charges should be reformed to create sharper price signals for generators and transmission-connected consumers. Some possible options include:

- **Levying TUoS charges on generation as well as demand**: based on the current CUSC methodology, generators face no costs associated with use of the transmission system. As discussed above, in the presence of congestion on the network, this can lead to inefficient decisions about where to locate new capacity and also in terms how plants are operated.
- **Introducing a locational element to transmission charges**: as set out in 4.40, there are two high-level options for creating locational charges: zonal (different charges applied in different geographic zones) or nodal (different charges

applied for each node of the transmission network). Either option can create price signals to encourage more efficient decisions by generators and transmission-connected consumers about where to locate, but both are more complex than the current CUSC methodology.

- **Separate TUoS charges for MIS and Dhofar regions**: given the differences in costs and patterns of electricity usage in MIS and Dhofar regions, a single TUoS charge covering both regions results in cross-subsidy. Separate TUoS charges would result in a more cost-reflective set of charges that better reflects the costs of transmission in each region.
- **Creating a separate charge to recoup the costs associated with dispatch and balancing**: this reform would separate the current TUoS charges into two separate charges: one recouping the costs associated with the use of system and the other recouping the costs of OETC's dispatch and balancing activities. This would potentially create a more cost-reflective set of charges that more accurately charges transmission users based on the demands that they are making on the transmission system.

Q14. In your view, should the existing system of TUoS charges be reformed to encourage more efficient decisions by generators and transmission-connected customers with respect to location and operation? If so, how?

Incentivizing more efficient consumption behaviors

5.4 There are a number of options for reforming the CUSC to create sharper incentives for more efficient consumption. These include:

- **Switching the basis of TUoS charging from single to multiple snapshots**: as set out above, allocating transmission charges based on an average of multiple snapshots of maximum system demand (separated by a window of time to ensure that snapshots don't occur during the same peak period) can help to create a more powerful incentive for suppliers to manage their peak demand.
- **Allocating a share of transmission costs based on annual demand**: setting the charge for use of the transmission system based on RUT (in addition to MTSD) creates an incentive for suppliers to manage total demand in addition to peak demand, improving incentives to use electricity efficiently.

5.5 Currently, the electricity tariffs faced by the majority of customers are not cost-reflective. These customers do not face an effective price signal about the impact that their consumption has on the transmission system. As such, better incentives could also be created through an expansion of cost-reflective tariffs to a wider set of consumers. While the reform of electricity tariffs is outside of the scope of this consultation, it is an issue that the Authority will keep under review.

Q15. In your view, should the existing system of TUoS charges be reformed to encourage more efficient consumption behaviors? If so, how?

Accommodating an increase in renewable generation

5.6 OPWP set out in the latest Seven Year Statement that there are plans to develop Oman's first large-scale solar Independent Power Producer (IPP) with a minimum capacity of 200 MW. Moreover, OPWP and PAEW recently established a joint task force for the development of wind power plants.[16] As such, we may expect to see an increase in the level of renewable energy capacity over the medium term (subject to these projects meeting technical and economic assessments).

5.7 As such, it may be prudent to consider reforms to the TUoS charges in order to accommodate an increase in renewable generation (this reform presupposes that a share of TUoS charges are levied on generation). For example, through adjusting TUoS charges based on the load factors of different generation sources in order to better reflect the demand that intermittent renewable generation makes on the transmission system.

Q16. In your view, should the existing system of TUoS charges be reformed to accommodate an increase in renewable electricity? If so, how? Q17. In your view, are there other reforms to the TUoS charging methodology (other than the areas set out above) that should be considered?

Reforms to the connection charging methodology

5.8 There are a number of reforms to the connection charging methodology that might be considered. These include:

- **Switching to a system of deep connection charges**: in the presence of network congestion, shallow connection charges may not capture the full cost of a new connection. As such, a system of deep connection charges (that charges users for the cost of connection asset as well as the costs of any necessary system additions and reinforcements) would provide an incentive to consider the wider system costs of their decision about where to locate. On the other hand, increasing the costs which must be borne by parties wishing to connect to the network may deter those parties from doing so, which may not be consistent with Oman's wider economic and social objectives.

[16] OPWP Seven Year Statement (2017-2023)

- **Switching the basis for connection charging from annuitized to up-front**: requiring generators and transmission-connected customers to pay the capital costs up-front (rather than through annuitized payments over the lifetime of the asset) would reduce the burden on OETC to finance this capital expenditure. However, as discussed in section 4, this would potentially raise issues of subsidy, inter-generational equity and may act as a deterrent to parties seeking to connect to the network, which may not be consistent with Oman's wider economic and social objectives.

5.9 In addition, the Authority will consider through OETC's price control review that is running in parallel to this consultation whether a specific incentive/penalty regime should be include within the price control framework to encourage efficient and timely connections.

Q18. In your view, should the existing system of connection charges be reformed? If so, how?

6. Timetable for review of transmission connection and use of system charges

6.1 The Authority will develop the revised CUSC in three stages:

- Key issues consultation – stakeholders are invited to comment on the key issues related to the reform of the connections and transmission charging methodology, as described in this document;
- Initial Proposals – the Authority issues initial proposals for the revised CUSC methodology, which stakeholders are invited to comment on;
- Final Proposals – the Authority issues final proposals for the revised CUSC methodology; and

Once the final proposals are agreed, OETC shall commence the modification procedure as set out in the CUSC methodology.

6.2 These stages will be conducted according to the timetable illustrated in Table 6 below.

Table 6: Timetable for the review of transmission and use of system charges

Consultation	
Authority issues consultation document	18 January 2018
Responses to consultation document	18 March 2018
Initial proposals	
Authority issues initial proposals	31 May 2018
Response to initial proposals	
Final proposals	
Authority issues final proposals	
OETC to respond to final proposals	
OETC to undertake modification process (as required)	
New CUSC methodology applies from	1 January 2019

6.3 In line with the timetable described, OETC and other stakeholders are invited to respond to this Consultation Paper by **18 March 2018**. Views are welcome on any aspect of the Consultation Paper, but particularly on those questions the Authority has outlined in this paper. Depending on the level of interest and response, the Authority may organize a stakeholder event in order to discuss the issues raised through the consultation.

Appendix 1 Consultation questions for OETC and other stakeholders

A1.1 While comments are invited on any aspect of this document, we have highlighted a number of specific questions that OETC and other stakeholders may wish to respond to. These questions are:

- Q1. Do you agree with the principles to guide the Authority's assessment of the CUSC methodology proposed in this section?
- Q2. Do you agree with the Authority's assessment of the existing connection charging methodology?
- Q3. In your view, has the use of a shallow charging methodology resulted in sub-optimal location decisions by generators and transmission-connected consumers?
- Q4. In your view, has the current methodology for calculating the TRC resulted in an unfair allocation of costs across connections?
- Q5. In your view, has the current approach of annuitizing connection costs led to cash flow/financeability issues for OETC?
- Q6. Do you agree with the Authority's assessment of the strengths and weaknesses of the existing CUSC methodology?
- Q7. In your view, has the existing transmission charging methodology resulted in, or could it result in, sub-optimal location and operation decisions by generators and transmission-connected consumers? As such, do you see that there would be benefits to generators paying a share of TUoS charges and/or introducing a locational element to the charges?
- Q8. In your view, would changing the basis for TUoS charges from single to multiple snapshots of maximum system demand result in more powerful incentives to reduce demand at peak periods? Should a share of TUoS charges reflect the RUT for each supplier?
- Q9. In your view, would there be a benefit to introducing a separate charge for dispatch and balancing?
- Q10. In your view, how would up-front charging for connections impact parties who were considering connecting to the transmission network?
- Q11. In your view, have there been instances of entities making speculative and/or inappropriately sized requests?

- Q12. If yes, do you believe that the current charging methodology has contributed to this issue?
- Q13. In your view, would there be advantages to introducing within the transmission price control a specific incentive to encourage efficient and timely connections?
- Q14. In your view, should the existing system of TUoS charges be reformed to encourage more efficient decisions by generators and transmission-connected customers with respect to location and operation? If so, how?
- Q15. In your view, should the existing system of TUoS charges be reformed to encourage more efficient consumption behaviors? If so, how?
- Q16. In your view, should the existing system of TUoS charges be reformed to accommodate an increase in renewable electricity? If so, how?
- Q17. In your view, are there other reforms to the TUoS charging methodology (other than the areas set out above) that should be considered?
- Q18. In your view, should the existing system of connection charges be reformed? If so, how?